VISTRA ENERGY

2019 ANNUAL REPORT

Upton 2 Solar and Energy Storage Facility

ABOUT VISTRA ENERGY

Vistra Energy (NYSE:VST) is a premier, integrated, Fortune 350 energy company based in Irving,Texas, providing essential resources for customers, commerce, and communities. Vistra combines an innovative, customer-centric approach to retail with safe, reliable, diverse, and efficient power generation. The company brings its products and services to market in 20 states and the District of Columbia, including six of the seven competitive retail markets in the U.S. and markets in Canada and Japan, as well. Serving nearly 5 million residential, commercial, and industrial retail customers with electricity and gas, Vistra is the largest competitive residential electricity provider in the country and offers over 40 renewable energy plans. The company is also the largest competitive power generator in the U.S. with a capacity of approximately 39,000 megawatts powered by a diverse portfolio of natural gas, nuclear, coal, solar, and battery energy storage facilities. In addition, the company is a large purchaser of wind power. The company is currently developing the largest battery storage system of its kind in the world – a 300-MW/1,200-MWh system in Moss Landing, California. Vistra is guided by four core principles: we do business the right way, we work as a team, we compete to win, and we care about our people, our neighbors, and our stakeholders.

4CHANGE energy · AMBIT ENERGY · BetterBuy energy · Brighten Energy · DYNEGY · Energy Rewards · express ENERGY · HOMEFIELD ENERGY · Luminant · PUBLIC POWER ENERGY SUPPLIER · TRIEAGLE ENERGY · TXU energy · USG&E

DEAR FELLOW VST STOCKHOLDERS

We referred to 2019 as the "Year of Execution" for Vistra Energy Corp. – and that it was. We focused our efforts on operating safely, achieving our financial guidance, returning capital to stockholders, and capturing our Dynegy merger synergy targets. Not only did we accomplish those goals, but we also continued to demonstrate the stability and strength of our integrated business model, expanded our retail footprint to be the largest competitor in the high-margin U.S. residential electricity markets with the acquisitions of Crius Energy Trust ("Crius") and Ambit Energy ("Ambit"), released a 10-year outlook for our company indicating the long-term resilience of our business, and formalized our commitment to take actions to address climate change by announcing greenhouse gas emissions reduction targets and by joining the Climate Leadership Council as a founding member.

Our success in 2019 and positive outlook for the year ahead are a direct result of executing on our business objectives with a focus and dedication to excellence. Importantly, the vastly different business model and asset profile we have been operating underpin the success we had in 2019 and in each of the four years since Vistra has been a public company – and will similarly position the company to continue our transformation in the age of climate change, leading to what we believe will be long-term strength and sustainability. I am pleased to share with you some of the highlights from 2019 and a vision for a sustainable future.

> *Our success in 2019 and positive outlook for the year ahead are a direct result of executing on our business objectives with a focus and dedication to excellence.*
>
> Curt Morgan
> President and Chief Executive Officer

Delivering on Financial Commitments and Returning Capital

Vistra continued to prove out the stability of the integrated model in 2019, delivering adjusted EBITDA from our ongoing operations of $3.393 billion[1], which marked the fourth year in a row – every year since Vistra has been a public company – that we have delivered financial results above the midpoint of our guidance. Vistra's 2019 adjusted free cash flow before growth from ongoing operations was $2.437 billion[1], results that exceeded the high end of our guidance range and equate to an EBITDA to free cash flow conversion ratio of nearly 72%. Vistra's ability to generate this robust free cash flow on an annual basis affords us the opportunity to both invest selectively in attractive opportunities and return a significant amount of capital to our stakeholders.

In fact, in 2019, we instituted a dividend program at $0.50 per share on an annualized basis and spent more than $650 million under our existing $1.75 billion share repurchase program, collectively returning approximately $900 million to stockholders. We also invested approximately $880 million on the Crius and Ambit acquisitions, which were executed at an average of 3.9 times enterprise value to EBITDA and were immediately accretive to Vistra's EBITDA per share and free cash flow per share. And last, we continued to optimize our balance sheet through refinancing approximately $8.3 billion of debt, reducing our annualized, after-tax interest expense by approximately $95 million. In total, since becoming a public company nearly four years ago, Vistra has returned approximately $5 billion to our financial stakeholders through share repurchases, debt retirement, and recurring and special dividends.

As we look ahead to 2020, our capital allocation focus is squarely on progressing toward our long-term leverage target of 2.5 times net debt to EBITDA. Whereas we dubbed 2019 the "Year of Execution," 2020 is the "Year of Financial Strength and Capital Allocation Clarity." A strong balance sheet is the foundation of our business model – low leverage levels and the achievement of an investment grade credit profile should allow Vistra to weather commodity cycles while positioning our management team to make sound investment decisions at the right times in the business cycles. Low leverage levels also support our ability to convert approximately 65–75% of our EBITDA to free cash flow on an annual basis, giving Vistra the ability to implement a diverse capital allocation plan.

Top: Vistra employees volunteering through the company's employee-led volunteer program Energy in Action

Middle: TXU Energy Bike MS team participates in Bike MS Round-Up Ride 2019

Bottom: Kendall Power Plant celebrates acceptance into OSHA VPP Star Program

Vistra has already announced an 8% increase to our dividend program for 2020, an increase that was at the high end of our expected 6–8% annual growth rate and which is supported by our stable and growing EBITDA profile and high free cash flow conversion ratio. We plan to further evaluate the appropriate size of our future dividends as part of our long-term capital allocation plan, which we expect to roll out in the second part of this year. We anticipate our long-term capital allocation plan will call for continued prudent and disciplined growth investments using on average about a quarter of our annual free cash flow, with the remaining significant free cash flow returned to stockholders through a mix of dividends and share repurchases.

Capturing Merger Synergies and Driving Operational Performance Improvement

Vistra's relentless focus on cost management and synergy capture is just another way we are creating value for our stockholders. Vistra closed the merger with Dynegy in April 2018, and in 2019, as we approached the full integration of the businesses, we realized approximately $270 million of the $290 million of full run-rate EBITDA synergies. The $290 million synergy target represents a nearly 30% increase from the $225 million of annual EBITDA synergies we first announced in October 2017.

Vistra has also been able to capture merger value through our Operations Performance Improvement ("OPI") program. The OPI program, which is designed to enable our generation fleet to operate as efficiently and cost-effectively as possible, has transformed the culture of our generation, mining, and procurement operations. Importantly, our OPI efforts have put our generation fleet in a strong position to remain viable as the supply landscape evolves in the markets where we operate. Vistra initially announced an expectation to achieve $125 million of annual OPI EBITDA enhancements, and we have since more than tripled that target to $425 million per year. In 2019, we realized $220 million from OPI; we expect to be at the full run-rate by year-end 2021.

In addition, after-tax free cash flow synergies from the merger continue to materialize, with Vistra now forecasting to achieve an annual run-rate of $320 million – an increase of nearly 400% above our initial projections – with $210 million realized in 2019. Finally, Vistra continues to believe we will be able to use the approximately $4 billion of Dynegy net operating loss carry forwards we inherited in the Dynegy merger, resulting in approximately $900 million in present value tax savings. The Dynegy merger continued to prove its value in 2019, and with integration now largely complete, we are moving forward as one company, set for success.

Operating Integrated Retail and Generation Businesses

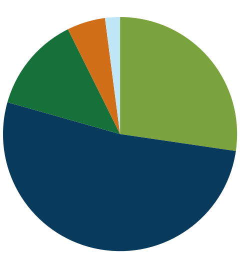
Another cornerstone of Vistra's success is our integrated business model. Pairing our retail and wholesale businesses creates higher and more stable cash flows, which we believe leads to consistent results and a more attractive investment. This is true, in part, because of the stability of our retail business and the in-the-money nature of our generation assets.

Retail

On the retail side, Vistra acquired two retailers in 2019, Crius and Ambit, adding strong brands to our retail portfolio and improving our generation-to-retail load match to nearly 60%, a 20% increase since the Dynegy acquisition. Following these transactions, Vistra's retail business operates in 19 states and the District of Columbia, has an industry-leading 26% market share across all U.S. competitive retail markets, and is the largest competitive electric retailer in the U.S. in the high-margin residential market.

Also in 2019, Vistra introduced two new brands, Brighten Energy and Better Buy, which supply affordable renewable energy options to customers in Illinois, Ohio, and Pennsylvania. Within the Texas markets, TXU Energy continued its legacy of innovative, customer-centric products by launching two new plans: TXU Energy Free Pass℠, giving customers free electricity on the seven days a month they use it the most, and TXU Energy Pure Solar℠, which gives consumers the option to turn any electricity plan into a renewable solar plan. These new products, combined with our current portfolio of electricity plans, sophisticated sales channel management, and brand strength, led to our Texas retail team growing residential customer counts for the second year in a row.

2019 Retail Volumes



Business	52%
Residential	27%
Muni-Agg	13%
Crius	5%
Ambit	2%

Generation

Vistra's generation assets are relatively young, highly efficient assets – with over 60% of our capacity coming from gas-fueled generation and more than 50% of our fleet comprised of technology-advantaged and flexible combined cycle gas turbines. We expect these gas assets will be a long-term critical resource for the electric grid, which is becoming increasingly dependent on intermittent renewable resources.

Our assets performed exceptionally well in 2019. We finished the year with commercial availability of approximately 95% compared to a target of 94%. This metric is critical to our operational success, as it measures our fleet's ability to capture gross margin from the market when the assets are in the money. As we move into 2020, we will continue to focus on achieving superior commercial availability and maintaining the reliability of our fleet, especially in the Texas ERCOT market with its tight supply/demand dynamics.

To provide reliable generation to our customers, we must operate not only efficiently, but also safely. Safety is our No. 1 priority – our people are our most important asset. As of Dec. 31, 2019, Vistra had 11 generation sites that have achieved VPP STAR status, the highest designation of OSHA's Voluntary Protection Programs, with 6 progressing toward this impressive distinction. During the year, we also rolled out a new company-wide safety program called Best Defense, which focuses on high-risk activities and adds defenses to ensure that if we fail, we do so safely. As we did in 2019, we will continue to emphasize the importance of safety in our operations and will always strive for zero incidents, accidents, and near-misses.

Also in 2019, Vistra continued to transform our generation portfolio to newer, more efficient, and less environmentally impactful technologies with the retirement of four coal plants in downstate Illinois, along with the announcement of a planned retirement of a fifth plant by the end of 2022. We also initiated and continue to support legislation in Illinois, the Coal to Solar and Energy Storage Act, that would provide a pathway to reinvest and repurpose existing coal-fueled power plant sites into solar and battery energy storage facilities, helping Illinois meet its clean energy goals while continuing to support economic vitality in impacted local communities. The repowering at existing power plant sites is part of our Environmental Justice strategy to bring no- to low-emitting resources to communities while using existing infrastructure and bringing tax base.

Growing the Business

In addition to completing the Crius and Ambit retail acquisitions in 2019, we continued to advance our battery storage business in California with the 300-MW/1,200-MWh Moss Landing project under construction and the execution of an agreement to develop a 20-MW battery storage project at our Oakland site – further examples of utilizing existing sites to bring environmentally friendly technology to consumers of electricity. The 300-MW/1,200-MWh project located at our Moss Landing site is expected to be online in the fourth quarter of 2020 and is one of the world's largest battery projects of its kind. The Moss Landing site is a world-class industrial site that has the capacity and existing infrastructure for substantial additional battery storage – and in a market like California that has a significant appetite for incremental battery storage, we expect we will be able to grow our operations at this site in the future.

In addition to the growth potential at our Moss Landing site, Vistra has a line of sight to a deep pipeline of renewable and battery projects, along with a demonstrated capability to identify, close, and capture value from retail acquisitions, giving us confidence in our ability to deploy on average a quarter of our free cash flow on an annual basis on highly attractive growth opportunities in the next several years.

Advancing our Sustainability Profile

Sustainability has become one of the most important priorities for companies – and it certainly is for Vistra. As an energy company with fossil fuels as part of its fuel source, Vistra must be a leader on climate change and provide stakeholders, most notably investors, with a view of our future and long-term sustainability. An important action Vistra took in 2019 was the announcement of our formalized commitment to combat climate change through long-term emissions reduction targets. Specifically, Vistra announced goals to achieve a 50% reduction in CO_2 equivalent emissions by 2030 and an 80% reduction in CO_2 equivalent emissions by 2050, each as compared to a 2010 baseline. We further announced an aspiration to achieve net-zero carbon emissions by 2050 if advancements in technology, market constructs, and public policy are supportive. As of Dec. 31, 2019, including the impact of retiring the four Illinois coal plants, we have reduced our CO_2 equivalent emissions by 42% compared to a 2010 baseline – meaning we have already achieved nearly 85% of our 2030 emissions reduction goal.

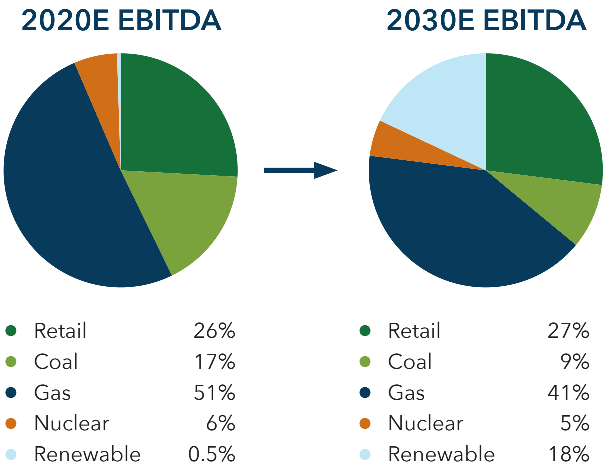
Vistra is not just taking action independently to reduce our carbon footprint – we are taking a leadership role in the effort to advance climate change policies on a national basis. In 2019, we joined the Climate Leadership Council (CLC) as a founding member, advocating for a consistently applied carbon fee and dividend approach as the ideal public policy solution to appropriately incentivize investments in carbon-free and carbon-reducing technologies. We further committed to contribute $1 million to Americans for Carbon Dividends, the advocacy arm of the CLC. Vistra believes the CLC's bipartisan climate roadmap, which promotes a national carbon dividend framework, is the right public policy solution to facilitate the country's transition to a lower-carbon future while maintaining the strength of the American economy.

Finally, Vistra formalized its sustainability governance structure in 2019, expanding the responsibility of the risk committee of our board of directors to include oversight of our sustainability program and naming a chief sustainability officer. Enhancing our environmental, social, and governance disclosures will be a key strategic focus for us in 2020. As such, please keep an eye out for our 2019 Sustainability Report, which will be released in June.

It is imperative that Vistra transform our company over the next several years to support its long-term sustainability. This transformation must be accomplished in an economically prudent fashion utilizing Vistra's strong cash flow, demonstrated investment experience, and power and natural gas capabilities. Vistra's 10-year view, shown below, provides a glimpse into the potential transformation of our business, forecasting an asset mix that we believe will support electric system reliability while providing customers with cost-effective energy that meets their sustainable preferences and significantly reduces our carbon footprint. We believe this


Ennis Power Plant

transformation is possible while also leaving Vistra with meaningful capital to return to shareholders. Notably, this 10-year view assumes Vistra will retire another approximately 7,200 MW of coal generation and invest in approximately 6,000 MW of renewables and battery storage between now and 2030.



In Closing

It is amazing to look back over three and a half years to October 2016, when our predecessor emerged from bankruptcy, and see how much our team has accomplished – enhancing safety practices and performance, growing EBITDA by more than 100%, returning capital to our stakeholders, and significantly changing the complexion of our generation fleet to one with a much lower carbon footprint. Specifically, we have grown the business through both investments in solar and battery storage projects and acquisitions of efficient gas assets and retail businesses – all executed at attractive returns well in excess of our internal investment threshold. Over the same period of time, we also identified nearly $1.5 billion of annual cost savings through merger synergies and internal restructuring activities and returned nearly $5 billion to our stakeholders. All of this was made possible because of our low leverage, low-cost integrated model, which now has a four-year demonstrated track record of delivering a stable and growing EBITDA profile with a very high conversion of EBITDA to free cash flow.

When I look ahead to the next 10 years, I see a sustainable company furthering its success. Our unique capabilities, with expertise managing risk, operating assets with scale and efficiency, and providing innovative products and services to our retail customers, make us well-positioned to capitalize on the transition to a lower-carbon economy, improving our environmental footprint while continuing to create value for our stockholders over the long-term. Our history has demonstrated that we have the discipline to be good stewards of your capital, returning meaningful excess cash to our financial stakeholders while investing in growth only when attractive opportunities arise. We remain optimistic that through continued execution and delivering on our commitments, investors will realize that we have a company with the ability to sustain performance and results over the long run, and our stock price will ultimately reflect its fundamental value.

Thank you for your interest in Vistra – we look forward to the year ahead!

Sincerely,

Curt Morgan
President and Chief Executive Officer

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[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.

Non-GAAP Reconciliations – Adjusted EBITDA

Year Ended December 31, 2019 (Unaudited) (Millions of Dollars)

	Retail	Ercot	PJM	NY/NE	MISO	Eliminations/ Corp and Other	Ongoing Operations Consolidated	Asset Closure	Vistra Energy Consolidated
Net income (loss)	$ 134	$ 1,368	$ 405	$ 188	$ 55	$ (1,115)	$ 1,035	$ (109)	$ 926
Income tax expense	–	–	–	–	–	290	290	–	290
Interest expense and related charges (a)	21	(8)	10	3	4	767	797	–	797
Depreciation and amortization (b)	292	581	537	208	19	76	1,713	–	1,713
EBITDA before Adjustments	**447**	**1,941**	**952**	**399**	**78**	**18**	**3,835**	**(109)**	**3,726**
Unrealized net (gain) or loss resulting from hedging transactions	278	(591)	(203)	(109)	(30)	(41)	(696)	–	(696)
Generation plant retirement expenses	–	–	–	–	12	–	12	42	54
Fresh start / purchase accounting impacts	23	(3)	(2)	4	15	(4)	33	(3)	30
Impacts of Tax Receivable Agreement	–	–	–	–	–	37	37	–	37
Non-cash compensation expenses	–	–	–	–	–	48	48	–	48
Transition and merger expenses	49	11	6	4	21	24	115	–	115
Other, net	10	12	7	9	7	(36)	9	2	11
Adjusted EBITDA	$ 807	$ 1,370	$ 760	$ 307	$ 103	$ 46	$ 3,393	$ (68)	$ 3,325

(a) Includes $220 million of unrealized mark-to-market net losses on interest rate swaps.
(b) Includes nuclear fuel amortization of $73 million in the ERCOT segment.

Non-GAAP Reconciliations – Adjusted Free Cash Flow

Year Ended December 31, 2019 (Unaudited) (Millions of Dollars)

	Ongoing Operations	Asset Closure	Vistra Energy Consolidated
Adjusted EBITDA	$ 3,393	$ (68)	$ 3,325
Interest paid, net (a)	(500)	–	(500)
Taxes received net of payments	76	–	76
Severance	(7)	(10)	(17)
Working capital and margin deposits	35	(17)	18
Reclamation and remediation	(15)	(101)	(116)
Transition and merger expense	(116)	–	(116)
Changes in other operating assets and liabilities	60	6	66
Cash provided by operating activities	$ 2,926	$ (190)	$ 2,736
Capital expenditures including LTSA prepayments and nuclear fuel purchases (b)	(609)	–	(609)
Development and growth expenditures	(104)	–	(104)
Ambit and Crius acquisitions	(880)	–	(880)
Purchases and sales of environmental credits and allowances, net	(125)	–	(125)
Other net investing activities (c)	(4)	5	1
Free cash flow	$ 1,204	$ (185)	$ 1,019
Working capital and margin deposits	(35)	16	(19)
Development and growth expenditures	104	–	104
Severance	7	10	17
Ambit and Crius acquisitions	880	–	880
Purchases and sales of environmental credits and allowances, net	125	–	125
Transition and merger expense	116	–	116
Transition capital expenditures	36	–	36
Adjusted free cash flow before growth	$ 2,437	$ (159)	$ 2,278

(a) Net of interest received.
(b) Includes $122 million LTSA prepaid capital expenditures.
(c) 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, 2019

— OR —

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

For the transition period from __ to __

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	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common stock, par value $0.01 per share	VST	New York Stock Exchange
Warrants	VST.WS.A	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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

As of June 28, 2019, the aggregate market value of the Vistra Energy Corp. common stock held by non-affiliates of the registrant was $8,654,325,784 based on the closing sale price as reported on the New York Stock Exchange.

As of February 24, 2020, there were 487,734,006 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 2020 annual meeting of stockholders are incorporated in Part III of this annual report on Form 10-K.

TABLE OF CONTENTS

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, Ambit Energy, Value Based Brands LLC, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power or U.S. Gas & Electric, 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, the Vistra Energy 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.

2018 Form 10-K	Vistra Energy's annual report on Form 10-K for the year ended December 31, 2018, filed with the SEC on February 28, 2019, except for Exhibits 31.1, 31.2, 32.1 and 32.2, which were amended in Vistra Energy's annual report on Form 10-K/A filed with the SEC on July 19, 2019
Ambit	Ambit Holdings, LLC, and/or its subsidiaries, depending on context
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 (Petition Date) by Energy Future Holdings Corp. (EFH Corp.) and the majority of its direct and indirect subsidiaries, including Energy Future Intermediate Holding Company LLC, Energy Future Competitive Holdings Company LLC and TCEH but excluding the Oncor Ring-Fenced Entities (Debtors). On the Effective Date, subsidiaries of TCEH that were Debtors in the Chapter 11 Cases (TCEH Debtors), along with certain other Debtors that became subsidiaries of Vistra Energy on that date (Contributed EFH Debtors) emerged from the Chapter 11 Cases.
CME	Chicago Mercantile Exchange
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
Crius	Crius Energy Trust and/or its subsidiaries, depending on context
CT	combustion turbine
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
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
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.
ESS	energy storage system
FERC	U.S. Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc. (a credit rating agency)
FTC	Federal Trade Commission
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	Intercontinental Exchange
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
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
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 formerly an indirect subsidiary of EFH Corp., that is engaged in regulated electricity transmission and distribution activities
Oncor Ring-Fenced Entities	Oncor Electric Delivery Holdings Company LLC and its direct and indirect subsidiaries, including Oncor
OPEB	postretirement employee benefits other than pensions
Parent	Vistra Energy Corp.
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
Public Power	Public Power, LLC, an indirect, wholly owned subsidiary of Vistra Energy, a REP in certain areas of PJM, NYISO, ISO-NE and MISO that is engaged in the retail sale of electricity to residential and business customers
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
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
ST	steam turbine
Tax Matters Agreement	Tax Matters Agreement, dated as of the Effective Date, by and among EFH Corp., Energy Future Intermediate Holding Company LLC, 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
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 whose major subsidiaries included Luminant and TXU Energy
TCEH Debtors	the subsidiaries of TCEH that were Debtors in the Chapter 11 Cases
TCEQ	Texas Commission on Environmental Quality
TRA	Tax Receivables Agreement, containing certain rights (TRA Rights) to receive payments from Vistra Energy related to certain tax benefits, including benefits realized as a result of certain transactions entered into at Emergence (see Note 8 to the Financial Statements)
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
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
TriEagle Energy	TriEagle Energy, LP, an indirect, wholly owned subsidiary of Vistra Energy, a REP in certain areas of ERCOT and PJM that is engaged in the retail sale of electricity to residential and business customers
TWh	terawatt-hours
U.S.	United States of America
U.S. Gas & Electric	U.S. Gas and Electric, Inc., an indirect, wholly owned subsidiary of Vistra Energy, a REP in certain areas of PJM, NYISO, ISO-NE and MISO that is engaged in the retail sale of electricity to residential and business customers
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 Intermediate	Vistra Intermediate Company LLC, a direct, wholly owned subsidiary of Vistra Energy
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 11 to the Financial Statements) and borrower under the Vistra Operations Credit Facilities
Vistra Operations Credit Facilities	Vistra Operations Company LLC's $5.425 billion senior secured financing facilities (see Note 11 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 primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy activities including electricity generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and natural gas to end users. We incorporated under Delaware General Corporate Law in 2016.

We serve approximately 4.6 million customers and operate in 20 states and the District of Columbia. Our generation fleet totals approximately 38,500 MW of generation capacity with a portfolio of natural gas, nuclear, coal, solar and battery energy storage 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. See Note 20 to the Financial Statements for further information concerning reportable business segments.

As of December 31, 2019, we had approximately 5,475 full-time employees, including approximately 1,690 employees under collective bargaining agreements.

Acquisitions and Merger

Ambit Transaction — On November 1, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the acquisition of Ambit (Ambit Transaction). Because the Ambit Transaction closed on November 1, 2019, Vistra Energy's consolidated financial statements and the notes related thereto do not include the financial condition or the operating results of Ambit and its subsidiaries prior to November 1, 2019. See Note 2 to the Financial Statements for a summary of the Ambit Transaction.

Crius Transaction — On July 15, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the acquisition of the equity interests of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius (Crius Transaction). Because the Crius Transaction closed on July 15, 2019, Vistra Energy's consolidated financial statements and the notes related thereto do not include the financial condition or the operating results of Crius and its subsidiaries prior to July 15, 2019. See Note 2 to the Financial Statements for a summary of the Crius Transaction.

Dynegy 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 to the Financial Statements for a summary of the Merger transaction.

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 is guided by our integrated business model because we believe it is our core competitive advantage and differentiates us from our non-integrated competitors by reducing the effects of commodity price movements and contributing to earnings and cash flow stability. Consequently, our integrated business model is at the core of our business strategy.

- *Disciplined capital allocation.* Vistra Energy 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 stockholders. A strong balance sheet helps to ensure Vistra Energy's interest expense is manageable in a variety of wholesale power price environments while giving Vistra Energy 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 Energy'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 stockholders through quarterly dividends and our share repurchase program (see Note 14 to the Financial Statements).

- *Superior customer service.* Through TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and US Gas & Electric, we serve the retail electricity and natural gas 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℠, TXU Energy's 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. 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 brands will result in high residential customer retention rates, particularly in Texas where our TXU Energy brand has maintained its residential customers in a highly competitive retail 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. 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 large and competitive markets, 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 the acquisition and development of high-quality energy infrastructure assets and businesses, including renewable energy and battery storage assets as well as retail businesses, that complement these core capabilities and enable us to achieve operational or financial synergies. 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, TXU Energy Aid and Ambit Cares campaigns. TXU Energy Aid serves as an integral resource for social service agencies that assist those in need across Texas pay their electricity bills. Ambit Cares partners with Feeding America® to assist those in need across the U.S. by fighting hunger through a network of food banks.

Recent Developments

Dividend Declaration — In February 2020, the Board declared a quarterly dividend of $0.135 per share that will be paid in March 2020.

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 natural gas 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 20 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, natural gas and related services to approximately 4.6 million customers. Substantially all of these activities are conducted by TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and US Gas & Electric across 19 U.S. states and the District of Columbia.

The largest portion of our retail operations are in Texas, where we provide retail electricity to approximately 2.3 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, strong brands, innovative products and services, having one of the lowest customer complaint rates according to the PUCT. As of December 31, 2019, we provided electricity to approximately 31% of the residential customers in ERCOT and for more than 10% of business customers' demand. 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, which give our customers choice, convenience and control over how and when they use electricity and related services. Our retail business also offers a comprehensive suite of green products and services, including 100% wind and solar options, as well as thermostats, dashboards and other programs designed to encourage reduced consumption and increased energy efficiency.

Our integrated power generation and wholesale operation allows us to efficiently obtain the electricity needed to serve our customers at the lowest cost. The integrated model enables us to 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) and achieve 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 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.

Outside of ERCOT, we also serve residential, municipal, commercial and industrial customers substantially through our Homefield Energy, Dynegy Energy Services, Public Power, US Gas & Electric and Ambit Energy retail businesses, through which we provide retail electricity, natural gas and related services to approximately 2.3 million customers in 18 states and the District of Columbia.

ERCOT Market

ERCOT is an ISO that manages the flow of electricity from approximately 82,000 MW of installed generation capacity to approximately 26 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. In 2019, ERCOT implemented a .25 standard deviation shift in the loss of load probability calculation using a single blended ORDC curve; these changes resulted in a more rapid escalation in power prices as operating reserves fall below defined thresholds. Subsequently, in 2020 ERCOT will implement an additional .25 standard deviation shift in the loss of load probability calculation, which is expected to result in a steeper price escalation during scarcity events in 2020 relative to 2019. 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. Other than during periods of "scarcity pricing," the price of power is typically set by natural gas-fueled generation facilities; as a result, historically low natural gas prices have had a corresponding impact on wholesale prices (see Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations – Key Operational Risks and Challenges*).

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 18,356 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 and a solar photovoltaic power generation facility totaling 180 MW. We also operate a 10 MW battery energy storage system (ESS) at our Upton 2 solar facility.

PJM Market

PJM is an RTO that manages the flow of electricity from approximately 180,000 MW of installed 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 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 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, four natural gas-fueled generation facilities totaling 1,346 MW and two oil-fueled generation facilities totaling 93 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 installed 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 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 190,000 MW of installed generation 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 Forward Capacity Auction 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 financial transmission rights 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 four power generation facilities located in Illinois totaling 3,408 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. Edwards is scheduled to be retired by the end of 2022 pursuant to the terms of a federal consent decree. We currently offer a portion of our MISO segment generating capacity and energy into PJM. Our Edwards and Newton generation facilities have 1,200 MW electrically tied into PJM through pseudo-tie arrangements. These pseudo-tie arrangements are scheduled to terminate on March 1, 2020, after which time Edwards and Newton will offer their generating capacity and energy solely into MISO.

CAISO Market

CAISO is an ISO that manages the flow of electricity to approximately 32 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.

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 2018 and 2019, we announced the planned development of a 300 MW ESS at our Moss Landing facility and a 20 MW ESS at our Oakland facility (see Note 3 to the Financial Statements).

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 numerous 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 18 years, is registered and protected by trademark law and is the only material intellectual property asset that we own. We have also acquired the trade names for Ambit Energy, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and US Gas & Electric through the Ambit Transaction, Crius Transaction and the Merger. As of December 31, 2019, we have reflected intangible assets on our balance sheet for our trade names of approximately $1.391 billion (see Note 6 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 13 to the Financial Statements for a discussion of litigation related to EPA reviews.

Climate Change

There is attention and interest nationally and internationally about global climate change and how greenhouse gas (GHG) emissions, such as carbon dioxide (CO_2), 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 116 million short tons of CO_2 in 2019.

We have already taken or announced significant steps to transition the fuel-mix and reduce the emissions profile of our generation fleet, including:

- *Acquisition of CCGTs* — In 2016 and 2017, we acquired 4,042 MW of CCGTs in Texas. In 2018, we acquired 15,448 MW of CCGTs in connection with the Merger.

- *Retirement of Coal Generation* — In 2018, we retired 4,167 MW of lignite/coal-fueled generation facilities in Texas. In 2019, we retired 2,068 MW of coal-fueled generation facilities in Illinois. We expect to retire an additional 585 MW of coal-fueled generation facilities in Illinois by the end of 2022.
- *Solar Development Project* — In 2018, we began commercial operation of our 180 MW Upton 2 solar facility.
- *Battery Energy Storage Projects* — In 2018, a 10 MW battery energy storage system (ESS) at our Upton 2 solar facility became operational. In 2018 and 2019, we announced the planned development of a 300 MW ESS at our Moss Landing facility and a 20 MW ESS at our Oakland facility. In 2019, we began construction of the Moss Landing ESS.

See Note 4 to the Financial Statements for discussion of our retirement of generation facilities and Note 3 for discussion of our solar and battery energy storage projects.

Greenhouse Gas Emissions

In August 2015, the EPA finalized rules to address GHG emissions from 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 filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court). In July 2019, petitioners filed a joint motion to dismiss in light of the EPA's new rule that replaces the Clean Power Plan, the Affordable Clean Energy rule, discussed below. In September 2019, the D.C. Circuit Court granted petitioners' motion to dismiss and dismissed all of the petitions challenging the Clean Power Plan as moot.

In July 2019, the EPA finalized a rule to repeal the Clean Power Plan, with new regulations addressing GHG emissions from existing coal-fueled electric generation units, referred to as the Affordable Clean Energy (ACE) rule. The ACE rule develops emission guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. States must submit their plans for regulating GHG emissions from existing facilities by July 2022. States where we operate coal plants (Texas, Illinois and Ohio) have begun the development of their state plans to comply with the rule. Environmental groups and certain states filed petitions for review of the ACE rule and the repeal of the Clean Power Plan in the D.C. Circuit Court. Additionally, in December 2018, the EPA issued proposed revisions to the emission standards for new, modified and reconstructed units. Vistra Energy submitted comments on that proposed rulemaking. While we cannot predict the outcome of these rulemakings and related legal proceedings, or estimate a range of reasonably probable costs, the rules, if implemented, 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 7.8 million tons of CO_2 during 2019. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2019 was approximately $5.65 per allowance. The spot market price of RGGI allowances required to operate our affected facilities during 2020 was $5.94 per allowance on February 24, 2020. 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 transitioned to a competitive auction process whereby allowances are 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.

Virginia — In May 2019, the Virginia Department of Environmental Quality issued a final rule to adopt a carbon cap-and trade program for fossil-fueled electricity generation units, including our Hopewell facility, beginning in 2020. The 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, and New Jersey formally rejoined RGGI in June 2019. In June 2019, New Jersey adopted two rules that govern New Jersey's reentry into the RGGI auction and distribution of the RGGI auction proceeds.

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. 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, various parties (including Luminant and 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 pending final review of the petitions for review. In March 2017, the Fifth Circuit Court granted a motion by the EPA to remand the rule back to the EPA for reconsideration. The stay of the rule (and the emission control requirements) remains in effect. The retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation. Further, we believe that these retirements and the BART rule (discussed below) obviates the need for any additional limits on our remaining Texas plants to address the requirements in the regional haze rule. 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. 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. Various parties 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 abated its proceedings until the EPA concludes the reconsideration process. In August 2018, the EPA issued a proposal to affirm the prior BART final rule and seeking comments on that proposal, which were due in October 2018. In November 2019, the EPA proposed additional revisions to the BART final rule, and we submitted comments on that proposal in January 2020. 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 May 2015, the EPA finalized a rule requiring 36 states, including Texas, Illinois and Ohio, to remove or replace either EPA-approved exemptions or affirmative defense provisions for excess emissions during upset events and unplanned maintenance and startup and shutdown events, referred to as the SIP Call. Various parties (including Luminant, the State of Texas and the State of Ohio) filed petitions for review of the EPA's final rule, and all of those petitions were consolidated in the D.C. Circuit Court. In April 2017, the D.C. Circuit Court ordered the case to be held in abeyance. In April 2019, the EPA Region 6 proposed a rule to withdraw the SIP Call with respect to the Texas affirmative defense provisions. We submitted comments on that proposed rulemaking in June 2019. In January 2020, the EPA took final action to withdraw the Texas SIP Call. While we cannot predict the timing or 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.

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 August 2019, the EPA issued a proposed Error Correction Rule for all three areas, which, if finalized, would revise its previous nonattainment designations and each area at issue would be designated unclassifiable. In September 2019, we submitted comments in support of the proposed Error Correction Rule. 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 challenged the 2015 ozone NAAQS; however, in August 2019, the D.C. Circuit Court generally upheld the 2015 ozone NAAQS but remanded the secondary ozone standard to the EPA for reconsideration. 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 filed a petition for judicial review challenging the EPA's action in the D.C. Circuit Court. In April 2019, the D.C. Circuit Court denied the states' petition for review, upholding the EPA's denial. 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 district 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 October 2019, the D.C. Circuit Court vacated the final rule, and in January 2020, New York and Connecticut filed a lawsuit against the EPA in the Southern District of New York to compel the EPA to comply with the court's June 2018 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, and Maryland filed a petition for review of the EPA's denial in the D.C. Circuit Court. 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.

In March 2018, the State of New York petitioned the EPA to find that emissions from hundreds of sources in nine states, including Illinois, Ohio, Virginia and West Virginia are significantly contributing to New York's nonattainment and interfering with New York's maintenance of the 2008 and 2015 ozone NAAQS. On October 18, 2019, the EPA took final action denying New York's petition. On October 29, 2019, New York, New Jersey and the City of New York filed a petition for review of the EPA's denial of the Section 126 petition. Briefing in the D.C. Circuit Court is ongoing.

Illinois Multi-Pollutant Standards (MPS)

In August 2019, changes proposed by the Illinois Pollution Control Board to the Illinois multi-pollutant standard rule (MPS rule), which places NOx, SO_2 and mercury emissions limits on our coal plants located in MISO went into effect. Under the revised MPS rule, our allowable SO_2 and NOx emissions from the MISO fleet are 48% and 42% lower, respectively, than prior to the rule changes. The revised MPS rule requires the continuous operation of existing selective catalytic reduction (SCR) control systems during the ozone season, requires SCR-controlled units to meet an ozone season NOx emission rate limit, and set an additional, site-specific annual SO_2 limit for our Joppa Power Station. Additionally, in 2019, the Company retired its Havana, Hennepin, Coffeen and Duck Creek plants in order to comply with the MPS rule's requirement to retire at least 2,000 MW of the company's generation in MISO. See Note 4 to the Financial Statements for information regarding the retirement of the four plants.

CAA Matters

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. In January 2020, the U.S. Department of Justice filed a complaint and proposed consent decree agreed to by Dynegy Zimmer, LLC in the U.S. District Court for the Southern District of Ohio that would resolve claims alleged in the 2008, 2010 and 2014 NOVs. The court has not yet entered the consent decree as effective. We believe that if the consent decree is entered by the court as proposed, it will not have a material impact on our results of operations, liquidity or financial condition.

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 against one of our subsidiaries that owns the Edwards Power Plant 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. In September 2019, the parties to the lawsuit announced a proposed settlement which was approved by the court in a consent decree in November 2019. The consent decree requires the retirement of the Edwards plant by the end of 2022 and funding for certain projects that benefit Peoria-area communities. See Note 4 to the Financial Statements for information regarding the expected retirement of the Edwards plant.

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 the construction, retrofitting, operation and closure of, and corrective action with respect to, 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 (i.e., cessation of placement of CCR material and corrective action necessary to reach the standards provided in the CCR rule and applicable state rules) 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 of state CCR permit programs.

In July 2018, the EPA published a final rule, which became effective in August 2018, that amends certain provisions of the CCR rule that the agency issued in 2015. Among other changes, the 2018 revisions extend closure deadlines to October 31, 2020, related to the aquifer location restriction and groundwater monitoring requirements. Also, in August 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule, including an applicability exemption for legacy impoundments. 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 March 2019, the D.C. Circuit Court granted the EPA's request for remand without vacatur. In December 2019, the EPA issued a proposed rule that would revise the closure deadlines for unlined CCR impoundments from October 31, 2020 to August 31, 2020 and establish new procedures for seeking extensions of the August 31, 2020 closure deadline. One method to receive an extension of the August 31, 2020 deadline would require notifying the EPA by May 2020 that the affected power generation facility will retire by either 2023 or 2028 depending upon the size of the affected facility's impoundments. If the rule is finalized as proposed, we may decide to avail ourselves of this retirement extension mechanism for some of our facilities. We filed comments on the proposal in January 2020. 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 — 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. These violation notices remain unresolved; however, 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 aforementioned D.C. Circuit Court decision in August 2018, 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, and we submitted revised plans 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. In May 2018, Prairie Rivers Network filed a citizen suit in federal court in Illinois against our subsidiary Dynegy Midwest Generation, LLC (DMG), 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 Seventh Circuit. That appeal is now stayed. In April 2019, PRN also filed a complaint against DMG before the Illinois Pollution Control Board (IPCB), alleging that groundwater flows allegedly associated with the ash impoundments at the Vermilion site have resulted in exceedances both of surface water standards and Illinois groundwater standards dating back to 1992. This matter is in the early stages. We dispute the allegations in both of these matters 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 and that notice has since been referred to the Illinois Attorney General.

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.

In July 2019, coal ash disposal and storage legislation in Illinois was enacted. The legislation addresses state requirements for the proper closure of coal ash ponds in the state of Illinois. The law tasks the IEPA and the IPCB to set up a series of guidelines, rules and permit requirements for closure of ash ponds. We anticipate IEPA's proposed rule will be issued in March 2020 and expect the rulemaking process should be completed by early 2021. Under the new law, coal ash impoundment owners would be required to submit a closure alternative analysis to the IEPA for the selection of the best method for coal ash remediation at a particular site. The law does not mandate closure by removal at any site. While we cannot predict the outcome of this rulemaking process, the final rule could have a material impact on our ARO, results of operations, liquidity or financial condition.

For all of the above matters, if certain corrective action measures, including groundwater treatment or removal of ash, 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, the D.C. Circuit Court's vacatur and remand of certain provisions of the EPA's 2015 CCR rule and the Illinois coal ash rulemaking, we cannot reasonably estimate the costs, or range of costs, of groundwater remediation, if any, that ultimately may be required. The currently anticipated CCR surface impoundment and landfill closure costs, as contained in our AROs, reflect the costs of closure methods that our operations and environmental services teams believe are appropriate and protective of the environment for each location.

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 to be approximately $16 million, depending on the final technology needed for compliance at our Illinois plants. 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 and potential plant retirements.

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, such as flue gas desulfurization (FGD), fly ash, bottom ash and flue gas mercury control wastewaters. 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 and administratively stayed the rule's compliance date deadlines. In August 2017, the EPA announced that its reconsideration of the 2015 ELG final rule would be limited to a review of the effluent limitations applicable to FGD and bottom ash wastewaters and the agency subsequently postponed the earliest compliance dates in the 2015 ELG Rule for the application of effluent limitations for FGD and bottom ash wastewaters from November 1, 2018 to November 1, 2020. Based on these administrative developments, the Fifth Circuit Court agreed to sever and hold in abeyance challenges to effluent limitations. The remainder of the case proceeded, and in April 2019 the Fifth Circuit Court vacated and remanded portions of the EPA's ELG rule pertaining to effluent limitations for legacy wastewater and leachate. In November 2019, the EPA issued a proposal that would extend the compliance deadline for FGD wastewater to no later than December 31, 2025 and maintains the December 31, 2023 compliance date for bottom ash transport water. The proposal also creates new sub-categories of facilities with more flexible FGD compliance options, including a retirement exemption to 2028 and a low utilization boiler exemption. The proposed rule also modified some of the FGD final effluent limitations. We filed comments on the proposal in January 2020.

Given the EPA's decision to reconsider the FGD and bottom ash wastewater provisions of the ELG rule, the rule postponing the ELG rule's earliest compliance dates for those provisions, the uncertainty stemming from the vacatur of the effluent limitations for legacy wastewater and leachate, and the intertwined relationship of the ELG rule with the CCR rule discussed above, 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.

Item 1A. RISK FACTORS

Please carefully consider the following discussion of significant factors, events, and uncertainties that make an investment in our securities risky. These factors, in addition to others specifically addressed in Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A)*, provide important information for the understanding of our forward-looking statements in this annual report on Form 10-K. If one or more of the factors, events and uncertainties discussed below or in the MD&A were to materialize, our business, results of operations, liquidity, financial condition, cash flows, reputation or prospects could be materially adversely affected. In addition, if one or more of such factors, events and uncertainties were to materialize, it could cause results or outcomes to differ materially from those contained in or implied by any forward-looking statement in this annual report on Form 10-K. 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 securities (including 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 natural gas 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 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 additional underperforming generation units, which could result in significant costs and have an adverse effect on our operating results.

A sustained decrease in the financial results from, or the value of, our generation units ultimately could result in the retirement or idling of additional 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 to 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 continued tightening of credit markets that began in 2008 and 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 elected not to apply hedge accounting to our commodity contracts, and we have designated contracts as normal purchases and 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 downgrade of Vistra Energy's or its applicable subsidiaries' credit ratings, or credit ratings of its issuances;
- 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 and the proposed phase out of LIBOR 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.

As of December 31, 2019, we had approximately \$11.2 billion of total indebtedness and approximately \$10.9 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 significant 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.

In addition, a portion of our indebtedness bears interest at variable interest rates, primarily based on LIBOR. Vistra Energy employs interest rate swaps to hedge our exposure to changes in LIBOR for a significant portion of this variable rate indebtedness. In 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index, calculated based on repurchase agreements backed by treasury securities. It is not possible to predict the effect of these proposed changes, other potential reforms or the establishment of any other alternative reference rates in the United Kingdom, the U.S. or elsewhere, including whether we will be able to amend the Vistra Operations Credit Facilities and/or our interest rate swaps to adequately reflect such changes, reforms or alternative reference rates. Accordingly, we could be exposed to increased costs with respect to our variable rate debt, which could have an adverse impact on extensions of our credit and/or we might not be fully hedged on the variable rate exposure on our swapped indebtedness. Any such increased costs or exposure could increase our cost of capital and have a material adverse effect on us.

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 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 in the fourth quarter of 2019 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 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 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 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% stockholders), the utilization of all NOLs 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 $455 million as of December 31, 2019 related to these future payment obligations (see Note 8 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, but not limited to, PURA, the Federal Power Act, the Atomic Energy Act, the Public Utility Regulatory Policies Act of 1978, the Clean Air Act (CAA), the Clean Water Act (CWA), the Resource Conservation and Recovery Act (RCRA), the Energy Policy Act of 2005, the Dodd-Frank Wall Street Reform and the Consumer Protection Act and the Telephone Consumer Protection Act), changing governmental policy and regulatory actions (including those of the FERC, the NERC, the RCT, the MSHA, the EPA, the NRC, the FTC, 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, rates for wholesale sales of electricity, mandatory reliability standards 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. As a result of the Crius Acquisition and the Ambit Acquisition, we became subject to the regulatory requirements of such markets, including regulations of the sale of natural gas in the California, District of Columbia, Illinois, Indiana, Kentucky, Maryland, New Jersey, New York, Michigan, Montana, Ohio, Pennsylvania and Virginia markets. Additionally, as further described below, Ambit operates a direct selling business model for the sale of electricity which subjects us to additional regulatory requirements in the states in which Ambit has retail electric customers and independent consultants. Ambit's direct selling business is subject to a number of federal and state regulations administered by the FTC and various state agencies as well as regulations in foreign markets administered by foreign agencies. Regulations applicable to network marketing organizations generally are directed at ensuring that product sales ultimately are made to consumers and that advancement within the organization is based on sales of the organization's products rather than investments in the organization or other non-retail sales related criteria. Because we have historically not been subject to the regulations of such markets and because we have not historically operated a direct selling business model, we may incur additional expenses, which may be material, to understand the relevant regulations and ensure that we are operating in compliance with such regulations.

Finally, the regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale and retail competition and the creation of incentives for the addition of large amounts of new renewable generation. For example, changes to, or development of, legislation that requires the use of clean renewable and alternate fuel sources or mandate the implementation of energy conservation programs that require the implementation of new technologies, could increase our capital expenditures and/or impact our financial condition. Additionally, in some retail energy markets, state legislators, government agencies and other interested parties have made proposals to change the use of market-based pricing, re-regulate areas of these markets that have previously been competitive, or permit electricity delivery companies to construct or acquire generating facilities. Other proposals to re-regulate the retail energy industry may be made, and legislative or other actions affecting electricity and natural gas deregulation or restructuring process may be delayed, discontinued or reversed in states in which we currently operate or may in the future operate. If such changes were to be enacted by a regulatory body, we may lose customers, incur higher costs and/or find it more difficult to acquire new customers. These changes are ongoing, and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business.

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 activities at our facilities to need to be changed to avoid violating applicable laws and regulations or elicit claims that historical 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 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, such as the EPA's ACE rule and proposed or future actions, including the Regional Haze program, 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. 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, developed or sold, 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 attention and interest 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 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 July 2019, the EPA finalized the ACE rule that develops emissions guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. States where we operate coal plants (Texas, Illinois and Ohio) have begun the development of their state plans to comply with the ACE rule. 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 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 reclaiming, 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.

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 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.

Ambit's direct selling business model could be found to be not in compliance with current or newly adopted laws or regulations in one or more markets, which could prevent us from conducting our business in these markets or require us to alter compensation practices under our direct selling business model, and harm our results of operations and financial condition.

Ambit's direct selling business model is subject to a number of federal and state regulations administered by the FTC and various federal and state agencies in the U.S. as well as regulations on direct selling in foreign markets administered by foreign agencies. We are subject to the risk that, in one or more markets, our direct selling business could be found by federal, state or foreign regulators not to be in compliance with applicable law or regulations, which may lead to our inability to obtain or maintain a license, permit, or similar certification. We may also be required to alter compensation practices under our direct selling business in order to comply with applicable federal, state, or foreign law or regulations. Regulations applicable to direct selling businesses generally are directed at preventing fraudulent or deceptive schemes, sometimes referred to as "pyramid" or "chain sales" schemes, by ensuring that product sales ultimately are made to consumers and that advancement within an organization is based on sales of the organization's products rather than investments in the organization or other non-retail sales-related criteria. The regulatory requirements concerning direct selling businesses do not include "bright line" rules and are inherently fact-based and, thus, we are subject to the risk that these laws or regulations or the enforcement or interpretation of these laws and regulations by governmental agencies or courts can change. The ambiguity surrounding these laws can also affect the public perception of the Company.

In the U.S., the FTC has entered into several highly publicized settlements pursuant to consent orders with direct selling companies that required those companies to modify their compensation plans and business models. Those settlements resulted from actions brought by the FTC involving a variety of alleged violations of consumer protection laws, including misleading earnings representations by the companies' independent distributors, as well as the legal validity of the companies' business model and distributor compensation plans. The consent order in each of these cases required the respective direct selling company to, among other things, pay a significant fine, revise its U.S. business model and compensation plan to comply with various restrictions on how it can compensate independent distributors and change its marketing practices to avoid misleading income representations. Although we strive to ensure that Ambit's overall business model and compensation plans are regulatory compliant in each of our markets, we cannot provide assurance that a regulator, if it were to review our business, would agree with our assessment and would not require us to change one or more aspects of our operations. Being the target of an investigation or enforcement action by the FTC could have a material adverse effect on our results of operations and financial condition.

We are also subject to the risk of private party challenges to the legality of our direct selling business. Some direct selling channels of other companies have been successfully challenged in the past, while other challenges to direct selling channels of other companies have been defeated. Adverse judicial determinations with respect to our direct selling channel, or in proceedings not involving us directly but which challenge the legality of direct selling channels, in any market in which we operate, could negatively impact our business. Violations of applicable law or of our policies and procedures by independent contractors participating in Ambit's direct selling channel could also reflect negatively on us or harm our business reputation. While we have implemented policies and procedures designed to govern independent contractor conduct and to protect the goodwill associated with Ambit's trademarks and tradenames, it can be difficult to enforce these policies and procedures because of the large number of independent contracts and their independent status. In addition, it is possible that a court could hold us civilly or criminally accountable based on vicarious liability because of the actions of those independent contractors or challenge the independent contractor status of those individuals.

Operational Risks

Volatile power supply costs and demand for power have and could in the future 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 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 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.

The substantial majority of 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. Our information technology systems and infrastructure are susceptible to damage, disruptions, or shutdowns due to power outages, hardware failures, programming errors, defects or other vulnerabilities, cyber-attacks, ransomware attacks, malware attacks, computer viruses, theft, misconduct by employees or other insiders, telecommunications failures, misuse, human errors or other catastrophic events. While we have controls in place designed to protect our infrastructure, such breaches and threats are becoming increasingly sophisticated, complex, change frequently and may be difficult to detect. Any such breach, disruption or similar event 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, which could have a material adverse effect on us. Any loss of confidential or proprietary data through a breach, unauthorized access, disruption, misuse or disclosure 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. We cannot provide any assurance that such events and impacts will not be material in the future, and our efforts to deter, identify and mitigate future breaches may require additional significant capital and may not be successful.

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 us to access, collect, store and transmit 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. Although we take precautions to protect the sensitive customer data that we are required to collect in order to conduct our business, if a significant breach of our information technology systems 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 are capital intensive and 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 human-made 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 obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, corrective action, disposal and monitoring relating to CCR.

As a result of electricity produced for decades at coal-fueled power plants in Illinois, Texas and Ohio, we manage large amounts of CCR material in surface impoundments, all in compliance with applicable regulatory requirements. In addition to the federal requirements under the CCR rule, CCR surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, increased operating and maintenance costs and/or result in closure of certain power generating facilities, which could affect the results of operations, financial position and cash flow of the Company. We have recognized ARO related to these CCR-related requirements. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than current estimates and could, therefore, materially impact earnings through increased compliance expenditures.

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, floods, storms, fires, earthquakes 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.

Risks that are beyond our control, including but not limited to acts of terrorism or related acts of war, natural disaster or human-made disaster, hostile cyber intrusions or other catastrophic events could have a material adverse effect on our financial condition, results of operations and cash flows.

Our business, including our generation facilities and the facilities of third parties on which we rely, may be impacted by an act of war, terrorist activities or other attacks or conflicts, epidemics, pandemics, severe weather conditions and other natural or human-made disasters, as well as events occurring in response to or in connection with them, which could result in disruption of our ability to generate, purchase, transmit or distribute electricity and/or natural gas for a significant period of time, otherwise disrupt our customer operations and/or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Hostile cyber intrusions, including those targeting information systems as well as electronic control systems used at the generating plants and for the distribution systems, could severely disrupt business operations and result in loss of service to customers, as well as significant expense to repair security breaches or system damage. Any such disruption could result in a significant decrease in revenues, significant additional capital and operating costs, including costs to implement additional security systems or personnel to purchase electricity and to replace or repair our assets beyond what could be recovered through insurance policies, higher insurance deductibles, higher premiums and more restrictive insurance policies, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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.

We may potentially be affected by emerging technologies that may over time affect change in capacity markets and the energy industry overall with the inclusion of distributed generation and clean technology.

Some of these emerging technologies are shale gas production, distributed renewable energy technologies, energy efficiency, broad consumer adoption of electric vehicles, distributed generation and energy storage devices. Such emerging technologies could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. These emerging technologies may also affect the financial viability of utility counterparties and could have significant impacts on wholesale market prices, which could ultimately have a material adverse effect on our financial condition, results of operations and cash flows could be materially adversely affected.

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, 2019, we had approximately 1,690 employees covered by collective bargaining agreements, of which approximately 670 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 June 2020 and November 2023, but remain effective 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 which we initiated 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.

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 (b)
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%
Total ERCOT Segment					18,356	
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 (b)
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%
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					3,408	
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					38,448	

(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.
(b) Ownership interest of 100% indicates fee simple ownership of the facility. Ownership of less than 100% indicates the share of ownership in the facility held by the Company.

Our wholesale commodity risk management group also procures renewable energy credits from renewable 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, 2019, Vistra Energy had long-term power purchase agreements to procure approximately 880 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 own and 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, which will occur in 2020. 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 96%, 101% and 84% in 2019, 2018 and 2017, 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 all of our 2020 and the majority of our 2021 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 10 generation facilities totaling 11,115 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 13 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.

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".

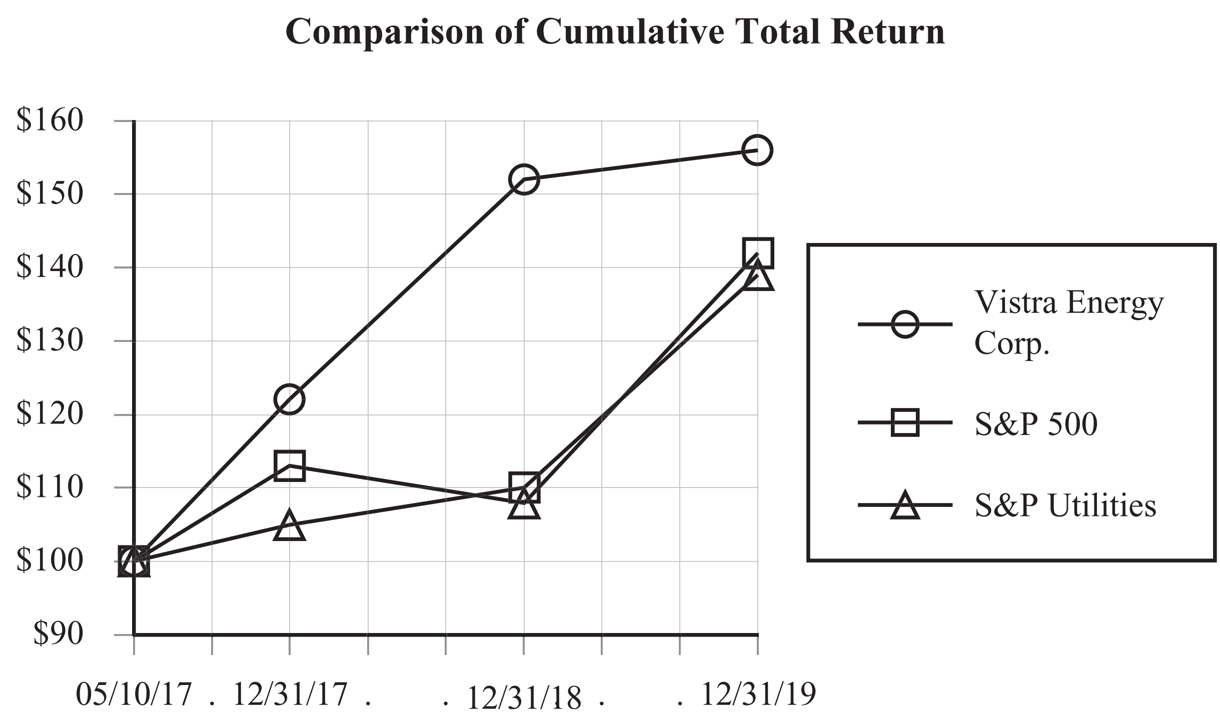
On April 9, 2018 (Merger Date), pursuant to the Merger Agreement, 94,409,573 shares of Vistra Energy common stock were issued to the former Dynegy stockholders, as well as converting stock options, equity-based awards, tangible equity units and warrants.

As of February 24, 2020, there were 487,734,006 shares of common stock issued and outstanding and 570 stockholders of record.

In November 2018, we announced that the Board had adopted a dividend program which we initiated in the first quarter of 2019. Our common stockholders are entitled to receive any such dividends or other distributions ratably. In February 2020, our Board declared a quarterly dividend of $0.135 per share that will be paid in March 2020. Each dividend under the program is 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, Delaware law and contractual limitations. For additional details, see Item 1A. *Risk Factors* and Note 14 to the Financial Statements

Stock Performance Graph

The performance graph below compares Vistra Energy's cumulative total return on common stock for the period from May 10, 2017 (the date we were listed on the NYSE) through December 31, 2019 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 Exchange Act, as amended, during the quarter ended December 31, 2019.

	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, 2019	674,438	$ 26.86	674,438	$ 335
November 1 - November 30, 2019	140,200	$ 26.55	140,200	$ 332
December 1 - December 31, 2019	—	$ —	—	$ 332
For the quarter ended December 31, 2019	814,638	$ 26.81	814,638	$ 332

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 purchased, and in November 2018, we announced that the Board had authorized an incremental share repurchase program under which up to $1.250 billion of our outstanding stock may be purchased, resulting in an aggregate $1.750 billion share repurchase program. The share repurchase program has no set expiration date and will continue until complete or terminated by the Board. At December 31, 2019, $332 million was available for additional repurchases under the Program. See Note 14 to the Financial Statements for more information concerning the share repurchase program.

Any purchases of shares of the Company's stock will be made in open market transactions at prevailing market prices, in privately negotiated transactions, pursuant to plans complying with the Exchange Act or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the share repurchase program or otherwise will be determined at our discretion and will depend on a number of factors, including our capital allocation priorities, 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.

Item 6. SELECTED FINANCIAL DATA

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

	Successor				Predecessor	
	Year Ended December 31, 2019 (a)	Year Ended December 31, 2018 (b)	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
Operating revenues	$ 11,809	$ 9,144	$ 5,430	$ 1,191	$ 3,973	$ 5,370
Impairment of goodwill	$ —	$ —	$ —	$ —	$ —	$ (2,200)
Impairment of long-lived assets	$ —	$ —	$ (25)	$ —	$ —	$ (2,541)
Operating income (loss)	$ 1,993	$ 491	$ 198	$ (161)	$ 568	$ (4,091)
Net income (loss) attributable to Vistra Energy/the Predecessor (c)	$ 928	$ (54)	$ (254)	$ (163)	$ 22,851	$ (4,677)
Cash provided by (used in) operating activities	$ 2,736	$ 1,471	$ 1,386	$ 81	$ (238)	$ 237
Net income (loss) per weighted average share of common stock outstanding — basic	$ 1.88	$ (0.11)	$ (0.59)	$ (0.38)		
Net income (loss) per weighted average share of common stock outstanding — diluted	$ 1.86	$ (0.11)	$ (0.59)	$ (0.38)		
Dividend declared per share of common stock	$ 0.50	$ —	$ —	$ 2.32		

	Successor				Predecessor
	At December 31,				At December 31, 2015
	2019	2018	2017	2016	
Balance Sheet Information:					
Total assets (d)(e)	$ 26,616	$ 26,024	$ 14,600	$ 15,167	$ 15,658
Property, plant and equipment — net (d)(e)	$ 13,914	$ 14,612	$ 4,820	$ 4,443	$ 9,349
Goodwill and intangible assets (f)	$ 5,301	$ 4,561	$ 4,437	$ 5,112	$ 1,331
Long-term debt including current maturities (f)	$ 10,379	$ 11,065	$ 4,423	$ 4,623	$ 19
Short-term borrowings and accounts receivable securitization program	$ 800	$ 339	$ —	$ —	$ —
Borrowings under debtor-in-possession credit facility	$ —	$ —	$ —	$ —	$ 1,425
Pre-Petition notes, loans and other debt reported as liabilities subject to compromise (f)	$ —	$ —	$ —	$ —	$ 31,668
Total stockholders' equity/membership interests	$ 7,959	$ 7,863	$ 6,342	$ 6,597	$ (22,884)

(a) For the year ended December 31, 2019, reflects the results of operations acquired in the Crius and Ambit Transactions.
(b) For the year ended December 31, 2018, reflects the results of operations acquired in the Merger.
(c) 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.
(d) At December 31, 2018, includes assets acquired in the Merger.
(e) Reflects the impacts of impairment charges related to long-lived assets of $2.541 billion in the year ended December 31, 2015.
(f) As of December 31, 2015, 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.

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

The following discussion and analysis of our financial condition and results of operations for the years ended December 31, 2019, 2018 and 2017 should be read in conjunction with our condensed consolidated financial statements and the notes to those statements. Results are impacted by the effects of the Ambit Transaction, the Crius Transaction and the Merger (see Note 2 to the Financial Statements). The discussion and analysis of our financial condition and results of operations for the year ended December 31, 2017 and for the year ended December 31, 2018 compared to the year ended December 31, 2017 are included in Item 7. Management's Discussion and Analysis of Financial Condition and Results in our 2018 Form 10-K and is incorporated herein by reference. Operational results for four facilities retired in late 2019 were recast from the MISO segment to the Asset Closure segment (see Note 4 to the Financial Statements). The recast is reflected in the results of operations for the years ended December 31, 2019 and 2018, but the four retired facilities were not owned by Vistra nor did the MISO segment exist during the year ended December 31, 2017. Therefore, the recast does not impact the comparison of the results of operations for the years ended December 31, 2018 and December 31, 2017 beyond the recast shown below for the year ended December 31, 2018.

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 primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and natural gas to end users.

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. See Note 20 to the Financial Statements for further information concerning reportable business segments.

Significant Activities and Events and Items Influencing Future Performance

Acquisitions and Merger

Ambit Transaction — On November 1, 2019 (Ambit Acquisition Date), Volt Asset Company, Inc., an indirect, wholly owned subsidiary of Vistra Energy, completed the acquisition of Ambit (Ambit Transaction). See Note 2 to the Financial Statements for a summary of the Ambit Transaction and business combination accounting.

Crius Transaction — On July 15, 2019, Vienna Acquisition B.C. Ltd., an indirect, wholly owned subsidiary of Vistra Energy, completed the acquisition of the equity interests of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius (Crius Transaction). See Note 2 to the Financial Statements for a summary of the Crius Transaction and business combination accounting.

Dynegy Merger Transaction — On the Merger Date, Vistra Energy and Dynegy completed the transactions contemplated by the Merger Agreement. 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

See Note 3 to the Financial Statements for a summary of our solar generation and battery energy storage projects. See Note 4 to the Financial Statements for a summary of our generation plant retirements in 2018 and 2019.

Dividend Program

In November 2018, we announced that the Board had adopted a dividend program which we initiated in the first quarter of 2019. See Note 14 to the Financial Statements for more information about our dividend program.

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 purchased, and in November 2018, we announced that the Board had authorized an incremental share repurchase program under which up to $1.250 billion of our outstanding stock may be purchased, resulting in an aggregate $1.750 billion share repurchase program. See Note 14 to the Financial Statements for more information concerning the share repurchase program, including shares repurchased and remaining amounts available under the program.

Debt Activity

We have stated our objective to reduce our consolidated net leverage. We also intend to continue to simplify and optimize our capital structure, maintain adequate liquidity and pursue opportunities to refinance our long-term debt to extend maturities and/or reduce ongoing interest expense. In 2019, we completed several transactions that we believe, in the aggregate, advanced all of these goals. See Note 11 to the Financial Statements for details of our long-term debt activity and Note 10 to the Financial Statements for details of the accounts receivable securitization program.

Capacity Markets

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

	2019-2020		2020-2021	2021-2022
	Base	CP	CP	CP
RTO zone (a)	$ 80.00	$ 100.00	$ 88.32	$ 140.00
ComEd zone	182.77	202.77	188.12	195.55
MAAC zone	80.00	100.00	86.04	140.00
EMAAC zone	99.77	119.77	187.87	165.73
ATSI zone	80.00	100.00	76.53	171.33
PPL zone	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 2022-2023, are as follows:

	2019-2020	2020-2021	2021-2022	2022-2023
Base auction capacity sold, net (MW)	837	—	—	—
CP auction capacity sold, net (MW)	8,342	8,582	8,963	—
Bilateral capacity sold, net (MW)	160	200	200	200
Total segment capacity sold, net (MW)	9,339	8,782	9,163	200
Average price per MW-day	$ 134.43	$ 130.04	$ 160.55	$ 170.00

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 2019	Winter 2019 - 2020
Price per kW-month	$ 1.30	$ 0.18

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 2022, are as follows:

	Winter 2019 - 2020	Summer 2020	Winter 2020 - 2021	Summer 2021	Winter 2021 - 2022
Auction capacity sold (MW)	102	—	—	—	—
Bilateral capacity sold (MW)	916	955	542	403	33
Total capacity sold (MW)	1,018	955	542	403	33
Average price per kW-month	$ 0.86	$ 1.82	$ 0.83	$ 2.69	$ 1.94

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

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Price per kW-month	$ 7.03	$ 5.30	$ 4.63	$ 3.80	$ —

Performance incentive rules 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. We continue to market and pursue longer term multi-year capacity transactions that extend planning year 2023-2024.

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Auction capacity sold (MW)	3,237	3,112	2,939	3,137	—
Bilateral capacity sold (MW)	71	150	170	95	20
Total capacity sold (MW)	3,308	3,262	3,109	3,232	20
Average price per kW-month	$ 6.91	$ 5.35	$ 4.58	$ 3.92	$ 4.93

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

	2019-2020
Price per MW-day	$ 2.99

MISO capacity sales through planning year 2022-2023 are as follows:

	2019-2020	2020-2021	2021-2022	2022-2023
Bilateral capacity sold in MISO (MW)	2,128	1,974	786	432
Base auction capacity sold in PJM (MW)	220	—	—	—
CP auction capacity sold in PJM (MW)	133	344	415	125
Total MISO segment capacity sold (MW)	2,481	2,318	1,201	557
Average price per kW-month	$ 3.81	$ 3.52	$ 5.06	$ 5.01

CAISO — Our capacity sales, aggregated by calendar year for 2020 through 2022 for Moss Landing, are as follows:

	2020	2021	2022
Bilateral capacity sold (Avg MW)	1,020	—	—

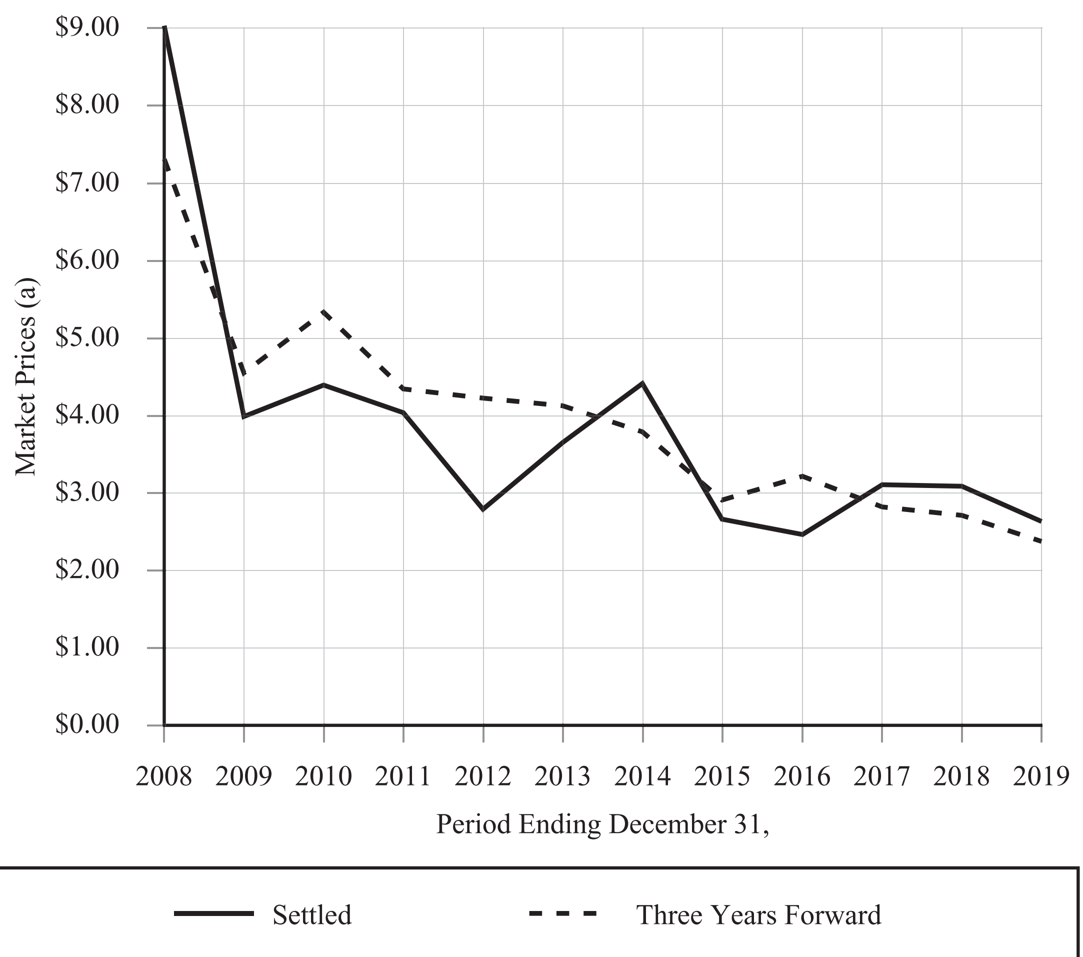
Key Operational Risks and Challenges

Following is a discussion of certain 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 business, results of operations, liquidity, financial condition, cash flow, reputation, prospects and the market price for our securities (including our common stock). See also Item 1A. Risk Factors in this annual report on Form 10-K for additional discussion on risks that could have a material effect on our results of operations, liquidity, financial condition, cash flow, reputation, prospects and the market price for our securities (including our common stock).

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, with exceptions such as those periods during which ERCOT power prices rise significantly as a result of the scarcity of available generation resources relative to power demand. In recent years, natural gas supply has outpaced demand primarily as a result of development and expansion of hydraulic fracturing in natural gas extraction; this supply/demand environment 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 significant portion of our generation capacity. Consequently, all other factors being equal, these nuclear-, lignite- and coal-fueled generation assets increase or decrease in value as wholesale electricity prices change either as a result of changes in natural gas prices or market heat rates, because of the effect on our operating margins. A persistent decline in the price of natural gas, if not offset by an increase in market heat rates, 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 and wholesale hedges.

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, particularly during periods when total demand is relatively low. However, increasing penetration of renewable generation capacity may also contribute to greater volatility of wholesale market prices independent of changes in the price of natural gas, given their intermittent nature. Decreases in market heat rates decrease the value of our generation assets because lower market heat rates result in lower wholesale electricity prices, and vice versa. In 2018 and prior years, even though market heat rates generally increased, wholesale electricity prices declined due to the greater effect of falling natural gas prices. Power price declines in the PJM, NYISO and ISO-NE markets in 2019 relative to 2018 also reflected the impact of lower natural gas prices. However, in the ERCOT market, wholesale market prices increased in 2019 relative to 2018, as the increase in market heat rates had a greater effect than the impact 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.

Estimated hedging levels for generation volumes in ERCOT, PJM, NYISO, ISO-NE, MISO and CAISO at December 31, 2019 were as follows:

	2020	2021
Coal/Nuclear/Renewable Generation:		
ERCOT	95 %	71 %
PJM	100 %	91 %
MISO	100 %	45 %
Gas Generation:		
ERCOT	81 %	10 %
PJM	84 %	19 %
NYISO/ISO-NE	100 %	45 %
CAISO	100 %	34 %

The following sensitivity table provides approximate estimates of the potential impact of movements in power prices and spark spreads (the difference between the power revenue and fuel expense of natural gas-fired generation as calculated using an assumed heat rate of 7.2 MWh/MMBtu) on realized pretax earnings (in millions) taking into account the hedge positions noted above for the periods presented. The residual gas position is calculated based on two steps: first, calculating the difference between actual heat rates of our natural gas generation units and the assumed 7.2 heat rate used to calculate the sensitivity to spark spreads; and second, calculating the residual natural gas exposure that is not already included in the gas generation spark spread sensitivity shown in the table below. The estimates related to price sensitivity are based on our expected generation, related hedges and forward prices as of December 31, 2019.

	Balance 2020 (a)		2021	
ERCOT:				
Coal/Nuclear/Renewable Generation: $2.50/MWh increase in power price	$	8	$	37
Coal/Nuclear/Renewable Generation: $2.50/MWh decrease in power price	$	(4)	$	(29)
Gas Generation: $1.00/MWh increase in spark spread	$	12	$	37
Gas Generation: $1.00/MWh decrease in spark spread	$	(4)	$	(30)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$	3	$	(33)
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$	(3)	$	28
PJM:				
Coal Generation: $2.50/MWh increase in power price	$	2	$	5
Coal Generation: $2.50/MWh decrease in power price	$	—	$	(2)
Gas Generation: $1.00/MWh increase in spark spread	$	6	$	28
Gas Generation: $1.00/MWh decrease in spark spread	$	(5)	$	(26)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$	(2)	$	(2)
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$	2	$	2
NYISO/ISO-NE:				
Gas Generation: $1.00/MWh increase in spark spread	$	1	$	8
Gas Generation: $1.00/MWh decrease in spark spread	$	—	$	(7)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$	2	$	—
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$	(2)	$	—
MISO/CAISO:				
Coal Generation: $2.50/MWh increase in power price	$	1	$	21
Coal Generation: $2.50/MWh decrease in power price	$	—	$	(21)
Gas Generation: $1.00/MWh increase in spark spread	$	—	$	3
Gas Generation: $1.00/MWh decrease in spark spread	$	—	$	(3)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$	1	$	—
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$	(1)	$	—

(a) Balance of 2020 is from January 1, 2020 through December 31, 2020.

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 and excluding customers acquired in the Ambit and Crius Transactions, our total retail customer counts increased approximately 2% in 2019, 2% in 2018 and slightly in 2017. Based upon December 31, 2019 results discussed below in *Results of Operations*, a 1% decline in retail customers in ERCOT would result in a decline in annual revenues of approximately $50 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, 2019, 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 2020 at December 31, 2019) to be approximately $2 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 13 to the Financial Statements to understand the importance and limits of our insurance protection.

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™, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. Gas & Electric 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 November 1, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the Ambit Transaction. On July 15, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the Crius Transaction. The Ambit Transaction and Crius Transaction are 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 their acquisition dates.

Determining fair values of assets acquired and liabilities assumed requires significant estimates and judgments. We determine fair value based on the estimated price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The acquired assets that involved the most subjectivity in determining fair value consisted of the customer relationship intangible assets. The assignment of fair value to the identifiable intangible assets requires judgment. We apply an income-based valuation methodology in measuring the customer relationships acquired, which include certain assumptions such as forecasted future cash flows, customer attrition rates, and discount rates. Customer relationship intangibles assets are generally amortized using an accelerated method based on historical customer attrition rates and reflecting the expected pattern in which the economic benefits are realized over their estimated useful lives.

On the Merger Date, Dynegy merged with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. The Merger was accounted for in accordance with 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.

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, a unit-specific power sales agreement and rail transportation contracts. 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.

Fresh-Start Reporting

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.

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. Where quoted market prices are not available, the fair value is based on unobservable inputs, which require significant judgment. Derivative instruments valued based on unobservable inputs primarily include (i) forward sales and purchases of electricity, natural gas and coal, (ii) electricity, natural gas and coal options, and (iii) financial transmission rights. 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 proprietary 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 15 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 16 to the Financial Statements for further discussion regarding derivative instruments.

Accounting for Income Taxes

Vistra Energy files a U.S. 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 U.S. Department of the 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 7 to the Financial Statements for further discussion of income tax matters.

Accounting for Tax Receivable Agreement

On the Effective Date, Vistra Energy entered into a tax receivable agreement (the TRA) with a transfer agent. Pursuant to the TRA, we issued the TRA Rights for the benefit of the first-lien creditors of TCEH 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, 2019, the TRA obligation has been adjusted to $455 million. During the year ended December 31, 2019, we recorded a decrease to the carrying value of the TRA obligation totaling $22 million as a result of adjustments to the timing of forecasted taxable income and state apportionment due to the expansion of Vistra Energy's state income tax profile, including Dynegy, Crius and Ambit acquisitions. At December 31, 2019, expected undiscounted payments under the TRA totaled $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 23.8%;
- 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 consolidated statements of operations 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 federal and state tax laws and regulations, changes in estimates of the amount or timing of future consolidated taxable income, utilization of acquired net operating losses, reversals of temporary book/tax differences and other items. Changes in those estimates are recognized as adjustments to the related TRA Rights liability, with offsetting impacts recorded in the consolidated statements of operations as Impacts of Tax Receivable Agreement. See Note 8 to the Financial Statements.

Asset Retirement Obligations (ARO)

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 ARO associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets. Changes to the estimate of the ARO requires us to make significant estimates and assumptions. Specifically, the estimates and assumptions required for the mining land reclamation related to lignite mining, such as the costs to fill in mining pits and interpreting the mining permit closure requirements, are complex and require a significant amount of judgment. To develop the estimate associated with the costs to fill in mining pits, we utilize a complex proprietary model to estimate the volume of the pit. A significant portion of the estimate is associated with the Asset Closure Segment, thus related to closed facilities with changes in the estimate recorded to the income statement.

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 in 2017 totaling $62 million as part of acquiring certain real property through the Alcoa contract settlement. During the year ended December 31, 2019, we transferred $135 million in ARO obligations to a third party for remediation. Any remaining unpaid third-party obligation was reclassified to other current liabilities and other noncurrent liabilities and deferred credits in our consolidated balance sheets.

At December 31, 2019, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.320 billion and includes an assumption that Vistra Energy receives a license extension of 20 years from the NRC to continue to operate the Comanche Peak facility. The costs to ultimately decommission that facility are recoverable through the regulatory rate making process as part of Oncor's delivery fees and therefore do not impact Vistra Energy's earnings.

See Note 21 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, Dynegy Energy Services, TriEagle Energy, U.S. Gas & Electric, Public Power and Ambit Energy trade names, 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 and ERCOT Generation reporting units exceeded its carrying value at October 1, 2019. 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, 2019, $1.960 billion of our goodwill was allocated to our ERCOT Retail reporting unit, $122 million was allocated to our ERCOT Generation reporting unit and $471 million arose in connection with the Ambit and Crius Transactions and is recorded at the retail segment, but has not been allocated to any reporting units and is pending completion of the purchase price allocations, 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 — Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

	Year Ended December 31, 2019	Year Ended December 31, 2018	Favorable (Unfavorable) $ Change
Operating revenues	$ 11,809	$ 9,144	$ 2,665
Fuel, purchased power costs and delivery fees	(5,742)	(5,036)	(706)
Operating costs	(1,530)	(1,297)	(233)
Depreciation and amortization	(1,640)	(1,394)	(246)
Selling, general and administrative expenses	(904)	(926)	22
Operating income	1,993	491	1,502
Other income	56	47	9
Other deductions	(15)	(5)	(10)
Interest expense and related charges	(797)	(572)	(225)
Impacts of Tax Receivable Agreement	(37)	(79)	42
Equity in earnings of unconsolidated investment	16	17	(1)
Income before income taxes	1,216	(101)	1,317
Income tax (expense) benefit	(290)	45	(335)
Net income (loss)	$ 926	$ (56)	$ 982

	Year Ended December 31, 2019							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Operating revenues	$ 6,872	$ 3,993	$ 2,442	$ 1,135	$ 658	$ 341	$ (3,632)	$ 11,809
Fuel, purchased power costs and delivery fees	(5,816)	(1,352)	(1,111)	(600)	(380)	(267)	3,784	(5,742)
Operating costs	(71)	(714)	(328)	(101)	(150)	(138)	(28)	(1,530)
Depreciation and amortization	(292)	(508)	(537)	(208)	(19)	—	(76)	(1,640)
Selling, general and administrative expenses	(538)	(79)	(54)	(47)	(57)	(43)	(86)	(904)
Operating income (loss)	155	1,340	412	179	52	(107)	(38)	1,993
Other income	—	28	—	—	7	3	18	56
Other deductions	—	(8)	(1)	—	—	(5)	(1)	(15)
Interest expense and related charges	(21)	8	(10)	(3)	(4)	—	(767)	(797)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	(37)	(37)
Equity in earnings of unconsolidated investment	—	—	4	12	—	—	—	16
Income (loss) before income taxes	134	1,368	405	188	55	(109)	(825)	1,216
Income tax expense	—	—	—	—	—	—	(290)	(290)
Net income (loss)	$ 134	$ 1,368	$ 405	$ 188	$ 55	$ (109)	$ (1,115)	$ 926

	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	$ 399	$ 371	$ (2,399)	$ 9,144
Fuel, purchased power costs and delivery fees	(4,126)	(1,521)	(917)	(485)	(174)	(286)	2,473	(5,036)
Operating costs	(39)	(677)	(243)	(74)	(136)	(109)	(19)	(1,297)
Depreciation and amortization	(318)	(416)	(413)	(152)	(9)	—	(86)	(1,394)
Selling, general and administrative expenses	(424)	(90)	(52)	(36)	(31)	(39)	(254)	(926)
Operating income (loss)	690	(70)	100	70	49	(63)	(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	48	(62)	(923)	(101)
Income tax benefit	—	—	—	—	—	—	45	45
Net income (loss)	$ 712	$ (55)	$ 100	$ 79	$ 48	$ (62)	$ (878)	$ (56)

In 2019, we focused on safe and reliable operations and produced results during the year that exceeded expectations. Our performance reflected the stability of our integrated model with the generation fleet operating reliably over the volatile ERCOT summer while our Retail segment delivered stable pricing and growth in ERCOT residential customer counts. As a result, we generated significant cash from operations, supporting the Company's ability to fund $713 million of capital expenditures (including LTSA prepayments, nuclear fuel and development and growth expenditures), invest $880 million in net cash for the Crius and Ambit Transactions, and advance our balanced capital allocation program, refinancing/repricing approximately $8.3 billion of debt, which lowered interest rates and extended maturities, and returning $899 million to stockholders through share repurchases and dividends.

Consolidated results increased $982 million to net income of $926 million in the year ended December 31, 2019 compared to the year ended December 31, 2018. The change in results was driven by a $1.076 billion increase in unrealized gains on hedging transactions, $339 million due to a full year of operations acquired in the Merger, $79 million due to operations acquired in the Crius Transaction and the Ambit Transaction, and $118 million in lower transition and merger expenses; partially offset by $246 million increase in depreciation and amortization, $225 million increase in interest expense and related charges, $335 million increase in income tax expense and $54 million in one-time costs associated with the fourth quarter 2019 plant retirements.

Interest expense and related charges increased $225 million to $797 million in the year ended December 31, 2019 compared to the year ended December 31, 2018 and reflected a $215 million change in unrealized mark-to-market losses on interest rate swaps and a $39 million increase in interest paid/accrued reflecting a full year with increased debt associated with the Merger. Debt extinguishment gains totaled of $21 million in 2019 compared to debt extinguishment losses of $27 million in 2018. See Note 21 to the Financial Statements.

For the years ended December 31, 2019 and 2018, the Impacts of the TRA totaled expense of $37 million and $79 million, respectively. See Note 8 to the Financial Statements for discussion of the impacts of the TRA Obligation.

For the year ended December 31, 2019, income tax expense totaled $290 million and the effective tax rate was 23.8%. For the year ended December 31, 2018, income tax benefit totaled $45 million and the effective tax rate was 44.6%. See Note 7 to the Financial Statements for reconciliation of the effective rates to the U.S. federal statutory rate.

Consolidated cash flow from operations produced $2.736 billion in the year ended December 31, 2019 compared to $1.471 billion produced in the year ended December 31, 2018.

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, (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 investors.

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 — Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

	Year Ended December 31, 2019	Year Ended December 31, 2018	Favorable (Unfavorable) $ Change
Net income (loss)	$ 926	$ (56)	$ 982
Income tax expense (benefit)	290	(45)	335
Interest expense and related charges (a)	797	572	225
Depreciation and amortization (b)	1,713	1,472	241
EBITDA	3,726	1,943	1,783
Unrealized net (gain) loss resulting from hedging transactions	(696)	380	(1,076)
Generation plant retirement expenses	54	—	54
Fresh start/purchase accounting impacts	30	41	(11)
Impacts of Tax Receivable Agreement	37	79	(42)
Non-cash compensation expenses	48	73	(25)
Transition and merger expenses	115	233	(118)
Other, net	11	(7)	18
Adjusted EBITDA, including Odessa earnout buybacks	$ 3,325	$ 2,742	$ 583
Odessa earnout buybacks	—	18	(18)
Adjusted EBITDA	$ 3,325	$ 2,760	$ 565

(a) Includes unrealized mark-to-market net losses on interest rate swaps of $220 million and $5 million for the years ended December 31, 2019 and 2018, respectively.

(b) Includes nuclear fuel amortization in the ERCOT segment of $73 million and $78 million for the years ended December 31, 2019 and 2018, respectively.

	Year Ended December 31, 2019							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Eliminations / Corporate and Other	Vistra Energy Consolidated
Net income (loss)	$ 134	$ 1,368	$ 405	$ 188	$ 55	$ (109)	$ (1,115)	$ 926
Income tax expense	—	—	—	—	—	—	290	290
Interest expense and related charges (a)	21	(8)	10	3	4	—	767	797
Depreciation and amortization (b)	292	581	537	208	19	—	76	1,713
EBITDA	447	1,941	952	399	78	(109)	18	3,726
Unrealized net (gain) loss resulting from hedging transactions	278	(591)	(203)	(109)	(30)	—	(41)	(696)
Generation plant retirement expenses	—	—	—	—	12	42	—	54
Fresh start/purchase accounting impacts	23	(3)	(2)	4	15	(3)	(4)	30
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	37	37
Non-cash compensation expenses	—	—	—	—	—	—	48	48
Transition and merger expenses	49	11	6	4	21	—	24	115
Other, net	10	12	7	9	7	2	(36)	11
Adjusted EBITDA	$ 807	$ 1,370	$ 760	$ 307	$ 103	$ (68)	$ 46	$ 3,325

(a) Includes $220 million of unrealized mark-to-market net losses on interest rate swaps.

(b) Includes nuclear fuel amortization of $73 million in the ERCOT segment.

	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	$ 48	$ (62)	$ (878)	$ (56)
Income tax benefit	—	—	—	—	—	—	(45)	(45)
Interest expense and related charges (a)	7	12	8	2	1	—	542	572
Depreciation and amortization (b)	318	494	413	152	9	—	86	1,472
EBITDA	1,037	451	521	233	58	(62)	(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	10	(4)	(23)	(7)
Adjusted EBITDA, including Odessa earnout buybacks	845	950	592	293	80	(63)	45	2,742
Odessa earnout buybacks		18						18
Adjusted EBITDA	$ 845	$ 968	$ 592	$ 293	$ 80	$ (63)	$ 45	$ 2,760

(a) Includes $5 million of unrealized mark-to-market net losses on interest rate swaps.
(b) Includes nuclear fuel amortization of $78 million in the ERCOT segment.

Retail Segment — Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

	Year Ended December 31, 2019	Year Ended December 31, 2018	Favorable (Unfavorable) Change
Operating revenues:			
Revenues in ERCOT	$ 5,061	$ 4,512	$ 549
Revenues in Northeast/Midwest	1,818	1,123	695
Amortization expense	(15)	(26)	11
Other revenues	8	(12)	20
Total operating revenues	**$ 6,872**	**$ 5,597**	**$ 1,275**
Fuel, purchased power costs and delivery fees:			
Purchases from affiliates	(3,571)	(2,846)	(725)
Unrealized net gains (losses) on hedging activities with affiliates	(305)	218	(523)
Unrealized net gains (losses) on hedging activities	19	—	19
Delivery fees	(1,629)	(1,493)	(136)
Other costs (a)	(330)	(5)	(325)
Total fuel, purchased power costs and delivery fees	**$ (5,816)**	**$ (4,126)**	**$ (1,690)**
Net income (loss)	**$ 134**	**$ 712**	**$ (578)**
Adjusted EBITDA	**$ 807**	**$ 845**	**$ (38)**
Retail sales volumes (GWh):			
Retail electricity sales volumes:			
Sales volumes in ERCOT	47,345	42,992	4,353
Sales volumes in Northeast/Midwest	30,255	20,739	9,516
Total retail electricity sales volumes	77,600	63,731	13,869
Weather (North Texas average) - percent of normal (b):			
Cooling degree days	96.0 %	103.0 %	
Heating degree days	113.0 %	112.0 %	

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(a) For the year ended December 31, 2019, includes $329 million of third-party power purchases, primarily related to the recent Ambit and Crius Transactions.

(b) Weather data is obtained from Weatherbank, Inc. For the year ended December 31, 2019, normal is defined as the average over the 10-year period from December 2009 to December 2018. For the year ended December 31, 2018, normal is defined as the average over the 10-year period from December 2008 to December 2017.

Net income decreased by $578 million to $134 million and Adjusted EBITDA decreased by $38 million to $807 million in the year ended December 31, 2019 compared to the year ended December 31, 2018.

Unfavorable margins in ERCOT driven by increased power costs and timing of multi-year retail contracts due to backwardation of power curves	$ (45)
Impact of Crius acquired in July 2019 and Ambit acquired in November 2019	79
Unfavorable weather in ERCOT	(34)
Other driven by higher bad debt expense and other SG&A expense	(38)
Change in Adjusted EBITDA	**$ (38)**
Change in depreciation and amortization expenses driven by reduced amortization of the retail customer relationship	29
Unfavorable impact of unrealized net losses on hedging activities	(484)
Higher transition and merger and other expenses	(85)
Change in Net income	**$ (578)**

Generation — Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

	Year Ended December 31,							
	ERCOT		PJM		NY/NE		MISO	
	2019	2018	2019	2018	2019	2018	2019	2018
Operating revenues:								
Electricity sales	$ 1,205	$ 1,289	$ 1,122	$ 775	$ 703	$ 582	$ 342	$ 275
Capacity	—	—	162	369	181	239	24	25
Sales to affiliates	2,213	1,829	921	628	153	44	285	100
Rolloff of unrealized net gains (losses) representing positions settled in the current period	371	404	16	44	—	5	(31)	14
Unrealized net gains (losses) on hedging activities	72	(689)	68	(61)	75	(42)	62	(27)
Unrealized net gains (losses) on hedging activities with affiliates	132	(198)	153	(33)	27	(3)	(7)	16
Other revenues	—	(1)	—	3	(4)	(8)	(17)	(4)
Operating revenues	3,993	2,634	2,442	1,725	1,135	817	658	399
Fuel, purchased power costs and delivery fees:								
Fuel for generation facilities and purchased power costs	(1,186)	(1,367)	(1,073)	(916)	(597)	(479)	(380)	(203)
Fuel for generation facilities and purchased power costs from affiliates	—	—	(1)	(8)	(1)	—	2	30
Unrealized (gains) losses from hedging activities	16	(15)	(34)	8	7	—	6	6
Ancillary and other costs	(182)	(139)	(3)	(1)	(9)	(6)	(8)	(7)
Fuel, purchased power costs and delivery fees	(1,352)	(1,521)	(1,111)	(917)	(600)	(485)	(380)	(174)
Net income (loss)	**$ 1,368**	**$ (55)**	**$ 405**	**$ 100**	**$ 188**	**$ 79**	**$ 55**	**$ 48**
Adjusted EBITDA	**$ 1,370**	**$ 968**	**$ 760**	**$ 592**	**$ 307**	**$ 293**	**$ 103**	**$ 80**
Production volumes (GWh):								
Natural gas facilities	39,433	35,790	37,403	26,431	18,152	14,605		
Lignite and coal facilities	27,743	29,151	14,067	14,102			17,172	12,724
Nuclear facilities	19,305	20,416						
Solar/Battery facilities	439	344						
Capacity factors:								
CCGT facilities	55.0 %	58.8 %	70.1 %	67.8 %	43.8 %	48.2 %		
Lignite and coal facilities	70.4 %	76.9 %	46.1 %	63.2 %			61.5 %	62.3 %
Nuclear facilities	95.8 %	101.3 %						
Weather - percent of normal (a):								
Cooling degree days	99 %	100 %	110 %	122 %	100 %	118 %	110 %	134 %
Heating degree days	111 %	113 %	99 %	103 %	102 %	103 %	99 %	97 %
Market pricing								
Average ERCOT North power price ($/MWh)	$ 35.93	$ 29.96						

	Year Ended December 31,							
	ERCOT		PJM		NY/NE		MISO	
	2019	2018	2019	2018	2019	2018	2019	2018
Average NYMEX Henry Hub natural gas price ($/MMBtu)	$ 2.51	$ 3.12						
Average Market On-Peak Power Prices ($MWh) (b):								
PJM West Hub			$ 30.87	$ 41.79				
AEP Dayton Hub			$ 31.02	$ 40.47				
NYISO Zone C					$ 25.90	$ 37.03		
Massachusetts Hub					$ 34.89	$ 50.11		
Indiana Hub							$ 31.23	$ 39.01
Northern Illinois Hub							$ 28.16	$ 34.46
Average natural gas price (c):								
TetcoM3 ($/MMBtu)			$ 2.39	$ 3.69				
Algonquin Citygates ($/MMBtu)					$ 3.17	$ 4.84		

(a) Reflects cooling degree days or heating degree days for the region based on Weather Services International (WSI) data.
(b) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.
(c) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

The following table presents changes in net income and Adjusted EBITDA for the year ended December 31, 2019 compared to the year ended December 31, 2018.

	Year Ended December 31, 2019 Compared to 2018			
	ERCOT	PJM	NY/NE	MISO
Favorable impact related to operations acquired in the Merger (a)	$ —	$ 201	$ 86	$ 56
Favorable/(unfavorable) change in revenue net of fuel	438	(20)	(63)	(62)
Favorable/(unfavorable) change in other operating costs	(39)	(4)	(2)	31
Favorable/(unfavorable) change in selling. general and administrative expenses	9	(4)	(3)	(3)
Other	(6)	(5)	(4)	1
Change in Adjusted EBITDA	**$ 402**	**$ 168**	**$ 14**	**$ 23**
Unfavorable change in depreciation and amortization	(87)	(124)	(56)	(10)
Unrealized net gains on hedging activities	1,089	245	149	21
Fresh start/purchase accounting impacts	(3)	1	5	(3)
Transition and merger expenses	(2)	8	(2)	(12)
Generation plant retirement expenses	—	—	—	(12)
Other (including interest)	24	7	(1)	—
Change in Net income	**$ 1,423**	**$ 305**	**$ 109**	**$ 7**

(a) Impact related to PJM, NY/NE and MISO operations acquired in the Merger are the combined results for the first quarter of 2019, for which there is no comparable period for 2018 due to the Merger date of April 9, 2018.

The change in ERCOT segment results was driven by a $438 million increase in generation revenue net of fuel reflecting higher realized power prices, lower natural gas fuel costs and a 1,219 GWh increase in total production volumes, partially driven by the first quarter production of the generation facilities acquired in the Merger.

The change in PJM segment results was driven by $201 million related to operations in the first quarter of 2019 acquired in the Merger, partially offset by lower generation in the second through fourth quarters.

The change in NY/NE segment results was driven by $86 million related to operations in the first quarter of 2019 acquired in the Merger, partially offset by lower generation in the second through fourth quarters.

The change in MISO segment results was driven by $52 million related to operations in the first quarter of 2019 acquired in the Merger and a $30 million decrease in operating costs during the second through fourth quarters, partially offset by a $57 million decrease in revenue net of fuel during the second through fourth quarters reflecting lower realized power prices and capacity revenue.

Asset Closure Segment — Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

	Year Ended December 31,		Favorable (Unfavorable) Change
	2019	2018	
Operating revenues	$ 341	$ 371	$ (30)
Fuel, purchased power costs and delivery fees	(267)	(286)	19
Operating costs	(138)	(109)	(29)
Selling, general and administrative expenses	(43)	(39)	(4)
Operating income (loss)	(107)	(63)	(44)
Other income	3	2	1
Other deductions	(5)	(1)	(4)
Net income (loss)	**$ (109)**	**$ (62)**	**$ (47)**
Adjusted EBITDA	**$ (68)**	**$ (63)**	**$ (5)**
Production volumes (GWh)	7,484	9,759	(2,275)

Results for the Asset Closure segment reflect the retirement of the Coffeen, Duck Creek, Havana and Hennepin plants in November and December 2019, the retirement of the Northeastern waste coal plant in October 2018, retirement of the Stuart and Killen plants in May 2018 (acquired in the Merger) and the retirement of the Monticello, Sandow and Big Brown plants in January and February 2018 (see Note 4 to the Financial Statements). Operating costs for the years ended December 31, 2019 and 2018 included ongoing costs associated with closing these plants.

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

The table below summarizes the changes in commodity contract assets and liabilities for the years ended December 31, 2019 and 2018. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $696 million in unrealized net gains for the year ended December 31, 2019 and $380 million in unrealized net losses for the year ended December 31, 2018, all arising from mark-to-market accounting for positions in the commodity contract portfolio.

	Year Ended December 31, 2019	Year Ended December 31, 2018
Commodity contract net liability at beginning of period	$ (850)	$ (96)
Settlements/termination of positions (a)	358	457
Changes in fair value of positions in the portfolio (b)	338	(837)
Acquired commodity contracts (c)	(28)	(454)
Other activity (d)	(97)	80
Commodity contract net liability at end of period	$ (279)	$ (850)

(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, 2019 and 2018 include reversals of $3 million and $17 million of previously recorded unrealized gains related to Vistra Energy beginning balances. The years ended December 31, 2019 and 2018 also include reversals of $124 million and $320 million, respectively, of previously recorded unrealized losses related to commodity contracts acquired in the Merger, Crius Acquisition and Ambit Acquisition. 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 on the Crius Acquisition, Ambit Acquisition in 2019 and on the Merger Date in 2018 (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, 2019, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Maturity dates of unrealized commodity contract net liability at December 31, 2019				
Source of fair value	Less than 1 year	1-3 years	4-5 years	Excess of 5 years	Total
Prices actively quoted	$ 74	$ (8)	$ (4)	$ —	$ 62
Prices provided by other external sources	(269)	2	—	—	(267)
Prices based on models	29	(22)	(6)	(75)	(74)
Total	$ (166)	$ (28)	$ (10)	$ (75)	$ (279)

FINANCIAL CONDITION

Operating Cash Flows

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018 — Cash provided by operating activities totaled $2.736 billion and $1.471 billion in the years ended December 31, 2019 and 2018, respectively. The favorable change of $1.265 billion was primarily driven by increased cash from operations reflecting operations acquired in the Merger, favorable operating results in the ERCOT segment and a decrease in cash used for margin deposits posted with third-parties.

Depreciation and Amortization — Depreciation and amortization expense reported as a reconciling adjustment in the consolidated statements of cash flows exceeds the amount reported in the consolidated statements of operations by $236 million, $139 million and $136 million for the year ended December 31, 2019, 2018 and 2017, respectively. The difference represented amortization of nuclear fuel, which is reported as fuel costs in the consolidated statements of operations consistent with industry practice, and amortization of intangible net assets and liabilities that are reported in various other consolidated statements of operations line items including operating revenues and fuel and purchased power costs and delivery fees.

Investing Cash Flows

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018 — Cash used in investing activities totaled $1,717 million and $101 million in the years ended December 31, 2019 and 2018, respectively. Capital expenditures (including LTSA prepayments, nuclear fuel purchases and growth and development expenditures) totaled $713 million and $530 million in the years ended December 31, 2019 and 2018, respectively. Cash used in investing activities in the year ended December 31, 2019 also reflected $880 million of net cash paid in the Crius and Ambit Transactions and $125 million of net purchases of environmental allowances. Cash used in investing activities in the year ended December 31, 2018 also reflected $445 million of cash acquired in the Merger.

In the years ended December 31, 2019 and 2018, capital expenditures, including LTSA prepayments, nuclear fuel purchases and growth and development expenditures, consisted of:

	Year Ended December 31,	
	2019	2018
Investments in generation and mining facilities	$ 333	$ 208
Nuclear fuel purchases	89	118
LTSA prepayments	122	100
Information technology and other corporate investments (a)	65	70
Growth and development expenditures	104	34
Capital expenditures, including LTSA prepayments, nuclear fuel purchases and growth and development expenditures	$ 713	$ 530

(a) Includes Comanche Peak repair costs.

Financing Cash Flows

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018 — Cash used in financing activities totaled $1.237 billion and $2.723 billion in the years ended December 31, 2019 and 2018, respectively. The decrease in cash used in financing activities was driven by:

- the issuance of $5.7 billion principal amount of Vistra Operations senior secured and unsecured notes in 2019 compared to the issuance of $1.0 billion principal amount of Vistra Operations senior unsecured notes in 2018;
- the amendment to the Vistra Operations Credit Facilities in 2018, including the repayment of $500 million in term loans;
- $350 million in net borrowings under the Revolving Credit Facility in 2019, and;
- $107 million decrease in cash paid for share repurchases in 2019 compared to 2018,

partially offset by:

- the net repayment of approximately $3.1 billion of term loans under the Vistra Operations Credit Facilities in 2019;

- cash tender offers and early redemptions to purchase senior unsecured notes assumed in the Merger of $3.0 billion in 2019 compared to $2.5 billion in 2018;
- $243 million of cash dividends paid to stockholders in 2019, and
- $228 million net decrease in incremental borrowings under the account receivable securitization program.

Debt Activity

See Note 11 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, 2019:

	December 31, 2019	December 31, 2018	Change
Cash and cash equivalents	$ 300	$ 636	$ (336)
Vistra Operations Credit Facilities — Revolving Credit Facility	1,426	1,135	291
Total available liquidity	$ 1,726	$ 1,771	$ (45)

The $45 million decrease in available liquidity in the year ended December 31, 2019 was primarily driven by $880 million of net cash paid in the Crius and Ambit Transactions, $656 million in cash paid for share repurchases, $713 million of capital expenditures (including LTSA prepayments, nuclear fuel and development and growth expenditures), $387 million principal amount of outstanding 7.625% Senior Notes due 2024 redeemed in November 2019, $243 million in dividends paid to shareholders, $203 million in debt tender offer and other financing fees and the $70 million redemption of mandatorily redeemable preferred stock in PrefCo, partially offset by cash from operations, $500 million of new Alternate LOC Facilities and $225 million of additional available capacity under the Revolving Credit Facility.

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 2020 are expected to total approximately $935 million and include:

- $532 million for investments in generation and mining facilities;
- $85 million for nuclear fuel purchases;
- $3 million for information technology and other corporate investments, and
- $315 million for growth and development expenditures.

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 11 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, 2019, we received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $202 million in cash has been posted with counterparties as compared to $361 million posted at December 31, 2018;
- $8 million in cash has been received from counterparties as compared to $4 million received at December 31, 2018;
- $1.150 billion in letters of credit have been posted with counterparties as compared to $1.185 billion posted at December 31, 2018, and
- $17 million in letters of credit have been received from counterparties as compared to $12 million received at December 31, 2018.

Income Tax Payments

In the next 12 months, we do not expect to make federal income tax payments due to Vistra Energy's use of NOL carryforwards. We expect to make approximately $26 million in state income tax payments, offset by $14 million in state tax refunds, and no TRA payments in the next 12 months. In addition, we expect to receive approximately $100 million in AMT refundable credits in the next 12 months.

In February 2019, we received a refund of $21 million related to Vistra Energy's 2017 federal tax return. In December 2019, we received a refund of $94 million related to alternative minimum tax credits claimed on Vistra Energy's 2018 tax return. For the year ended December 31, 2019, there were no federal income tax payments, $39 million in state income tax payments and $2 million in TRA payments.

Capitalization

Our capitalization ratios consisted of 56% and 58% long-term debt (less amounts due currently) and 44% and 42% shareholders' equity at December 31, 2019 and 2018, respectively. Total long-term debt (including amounts due currently) to capitalization was 57% and 58% at December 31, 2019 and 2018, 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, 2019, we were in compliance with this financial covenant.

See Note 11 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, 2019, Vistra Energy has posted letters of credit in the amount of $38 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 $316 million in the form of letters of credit, $10 million in the form of a surety bond and $8 million of cash at December 31, 2019 (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 $3.05 billion at December 31, 2019, including $350 million of cash borrowings under the Revolving Credit Facility) 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 equal to or above a threshold defined in the applicable agreement that results in the acceleration of such debt, would give such 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 (i) the Vistra Operations' Senior Unsecured Indentures and the Senior Secured Indenture, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary 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, or (ii) with respect to the Vistra Energy Senior Unsecured Indentures (except with respect to the Consent Senior Notes), a default under any document evidencing indebtedness for borrowed money by Vistra Energy or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $100 million or more, may result in a cross default under the Vistra Operations Senior Unsecured Notes, the Senior Secured Notes, the Vistra Energy Senior Unsecured Notes (except with respect to the Consent Senior Notes), the Vistra Operations Credit Facilities, the Receivables Facility, the Alternate LOC Facilities, and other current or future documents evidencing any indebtedness for borrowed money by the applicable borrower or issuer, as the case may be, and the applicable Guarantor Subsidiaries party thereto.

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 Facility 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 Alternate LOC Facilities, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary 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 Alternate LOC Facilities.

Contractual Obligations and Commitments

The following table summarizes the amounts and related maturities of our contractual cash obligations at December 31, 2019. See Notes 11 and 13 to the Financial Statements for additional disclosures regarding debt 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 (a)	$ 273	$ 136	$ 2,076	$ 7,949	$ 10,434
Debt – interest	502	967	954	912	3,335
Operating and finance leases	29	42	36	82	189
Long-term service and maintenance contracts	167	324	313	1,975	2,779
Obligations under commodity purchase and services agreements (b)	1,378	733	709	974	3,794
Total contractual cash obligations	$ 2,349	$ 2,202	$ 4,088	$ 11,892	$ 20,531

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(a) Includes $2.7 billion principal amount of term loans under the Vistra Operations Credit Facility, $3.1 billion principal amount of Vistra Operations senior secured notes, $3.6 billion principal amount of Vistra Operations senior unsecured notes, $747 million principal amount of Vistra Energy senior unsecured notes and $287 million principal amount of other long-term debt, including forward capacity agreements and equipment financing agreements. Excludes short-term borrowings, the accounts receivable securitization program and 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 2019 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 8 to the Financial Statements);
- asset retirement obligations (see Note 21 to the Financial Statements);
- arrangements between affiliated entities and intercompany debt (see Note 19 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 13 to the Financial Statements for discussion of guarantees.

OFF–BALANCE SHEET ARRANGEMENTS

As of December 31, 2019, we have no off-balance sheet arrangements, other than certain investments in energy and energy-related entities that are accounted for under the equity method of accounting which are not expected to have any material impact on our financial condition, results of operations or liquidity.

COMMITMENTS AND CONTINGENCIES

See Note 13 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.

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.

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.

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 2020 for the year ended December 31, 2019 and December 2019 for the year ended December 31, 2018.

	Year Ended December 31,	
	2019	2018
Month-end average VaR	$ 263	$ 182
Month-end high VaR	$ 520	$ 267
Month-end low VaR	$ 103	$ 65

The increase in the VaR risk measures in 2019 was primarily driven by an increase in volatility in ERCOT as compared to the prior year.

Interest Rate Risk

The following table provides information concerning our financial instruments at December 31, 2019 and 2018 that are sensitive to changes in interest rates. Debt amounts consist of the Vistra Operations Credit Facilities. See Note 11 to the Financial Statements for further discussion of these financial instruments.

	Expected Maturity Date						2019 Total Carrying Amount	2019 Total Fair Value	2018 Total Carrying Amount	2018 Total Fair Value
	2020	2021	2022	2023	2024	There-after				
	(millions of dollars, except percentages)									
Long-term debt, including current maturities (a):										
Variable rate debt amount	$ 27	$ 27	$ 27	$ 27	$ 27	$ 2,565	$ 2,700	$ 2,717	$ 5,813	$ 5,599
Average interest rate (b)	3.55 %	3.55 %	3.55 %	3.55 %	3.55 %	3.55 %	3.55 %		4.55 %	
Debt swapped to fixed (c):										
Notional amount	$ —	$ —	$ —	$ 3,000	$ 720	$ 3,000	$ 6,720		$ 7,717	
Average pay rate	3.77 %	3.77 %	3.77 %	4.10 %	4.75 %	4.77 %				
Average receive rate	3.54 %	3.54 %	3.54 %	3.43 %	3.21 %	3.21 %				
Debt swapped to variable (c):										
Notional amount	$ —	$ —	$ —	$ 700	$ 720	$ 700	$ 2,120		$ —	
Average pay rate	3.54 %	3.54 %	3.54 %	3.47 %	3.23 %	3.21 %				
Average receive rate	3.21 %	3.21 %	3.21 %	3.22 %	3.30 %	3.30 %				

(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, 2019.
(c) Interest rate swaps have maturity dates through July 2026.

At December 31, 2019, 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 $9 million taking into account the interest rate swaps discussed in Note 11 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 16 to the Financial Statements for further discussion of this exposure.

Bankruptcies — We are party to (i) certain gas transportation agreements with PG&E and (ii) a long-term resource adequacy contract with PG&E in connection with the Moss Landing battery storage project, which was approved by the California Public Utilities Commission (CPUC) in November 2018. PG&E filed for Chapter 11 bankruptcy protection in January 2019. On October 15, 2019, PG&E filed a motion in its bankruptcy proceeding requesting approval of the assumption of the resource adequacy contract. In early November 2019, the bankruptcy court approved the assumption motion subject to the CPUC approving the terms of the amendment. The CPUC approved the terms of the amendment on January 22, 2020 so the resource adequacy contract as amended is now assumed and fully enforceable against PG&E.

As of December 31, 2019, 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 be required to seek alternative, higher-cost fuel transportation methods if any of the terms of the gas transportation agreements are not honored by PG&E or the gas transportation agreements 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 $1.407 billion at December 31, 2019.

At December 31, 2019, Retail segment credit exposure totaled $1.024 billion, including $1.008 billion of trade accounts receivable and $16 million related to derivative assets. Cash deposits and letters of credit held as collateral for these receivables totaled $53 million, resulting in a net exposure of $971 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, 2019, aggregate ERCOT, PJM, NY/NE and MISO segments credit exposure totaled $383 million including $316 million related to derivative assets and $67 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 $382 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, 2019. 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	$ 347	$ —	$ 347
Below investment grade or no rating	36	1	35
Totals	$ 383	$ 1	$ 382

Significant (10% or greater) concentration of credit exposure exists with two counterparties, which represented an aggregate $204 million, or 53%, 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.

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 annual report on Form 10-K 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 the Coal Combustion Residuals Rule, 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 or direct-selling businesses;
- adverse publicity associated with our retail products or direct selling businesses, including our ability to address the marketplace and regulators regarding our compliance with applicable laws;
- 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 or changes in laws or regulations relating to independent contractor status;
- 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 businesses acquired by Vistra Energy and our ability to successfully capture the full amount of projected operational and financial synergies relating to such transactions, 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 subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, consolidated statements of comprehensive income (loss), consolidated statements of cash flows, and consolidated statement of changes in equity, for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2020 expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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.

Critical Audit Matters

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

Tax Receivable Agreement Obligation – Refer to Notes 1 and 8 to the financial statements

Critical Audit Matter Description

The Company has a tax receivable agreement (TRA) obligation that requires the Company to make annual payments to the TRA rights holders based on cash savings in income tax resulting from a step up in the tax basis of certain assets upon emergence from bankruptcy in 2016. The carrying value of the TRA obligation is based on the discounted amount of forecasted payments to the TRA rights holders. Determining the carrying value of the TRA obligation requires management to make significant estimates and assumptions in preparing its forecast of taxable income for a period of approximately 40 years. Changes to either the estimated timing or amount of expected TRA payments impact the carrying value of the obligation. As of December 31, 2019, the carrying value of the TRA obligation totaled $455 million.

Given the significant judgements made by management to estimate the TRA obligation, performing audit procedures to evaluate the reasonableness of management's estimate and assumptions related to the estimated future taxable income required a high degree of auditor judgement and an increased extent of effort, including the need to involve our income tax specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to estimated future taxable income included the following, among others:

- We tested the effectiveness of controls over management's determination of the TRA obligation carrying amount, including controls over developing the estimated future taxable income.
- With the assistance of our income tax specialists, we evaluated the following elements in testing management's estimated future taxable income:
  - The application of tax laws and regulations.
  - Future reversals of existing temporary differences including the timing and amount of loss carryforwards.
- We evaluated the reasonableness of management's estimates of future taxable income by comparing the estimates to:
  - Historical taxable income.
  - Internal communications to management and the Board of Directors.
  - Forecasted information included in Company press releases as well as in analyst and industry reports for the Company.
- We assessed the consistency of future taxable income with evidence obtained in other areas of the audit.

Fair Value Measurements – Level 3 Derivative Assets and Liabilities – Refer to Notes 1 and 15 to the financial statements

Critical Audit Matter Description

The Company has numerous derivative assets and liabilities. The fair values of a portion of these derivative instruments are based on complex proprietary models and/or unobservable inputs. These derivative financial instruments include (1) forward sales and purchases of electricity, natural gas, and coal; (2) electricity, natural gas, and coal options; and (3) financial transmission rights. Under accounting principles generally accepted in the United States of America, these financial instruments are generally classified as Level 3 assets or liabilities. As of December 31, 2019, the fair value of the Level 3 derivative assets and liabilities totaled $239 million and $313 million, respectively.

Given management uses complex proprietary models and/or unobservable inputs to estimate the fair value of Level 3 assets and liabilities, performing audit procedures to evaluate the appropriateness of these models and inputs required a high degree of auditor judgment and an increased extent of effort, including the need to involve our energy commodity fair value specialists who possess significant quantitative and modeling expertise.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the proprietary models and unobservable inputs used by management to estimate the fair value of Level 3 derivative assets and liabilities included the following, among others:

- We tested the effectiveness of controls over derivative asset and liability valuations, including controls related to price verification of illiquid price curves.
- We assessed the consistency by which management has applied significant unobservable valuation assumptions.
- We obtained the Company's complete listing of derivative assets and liabilities and related fair values as of December 31, 2019, to confirm our understanding of the types of instruments outstanding and performed sensitivity analysis to understand the most significant assumptions impacting fair value.
- With the assistance of our energy commodity fair value specialists, we developed independent estimates of the fair value of a sample of Level 3 derivative instruments and compared our estimates to the Company's estimates.

Asset Retirement Obligations – Mining Land Reclamation – Refer to Notes 1 and 21 to the financial statements

Critical Audit Matter Description

The Company recognizes asset retirement obligations associated with legal, regulatory, contractual, or constructive retirement requirements of tangible long-lived assets. 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 disposal costs. The estimate of the asset retirement obligations requires management to make significant estimates and assumptions. Specifically, the estimates and assumptions required for the mining land reclamation related to lignite mining, such as the costs to fill in mining pits and interpreting the mining permit closure requirements, are complex and require a significant amount of judgment. To develop the estimate associated with the costs to fill in mining pits, the Company utilizes a complex proprietary model to estimate the volume of the pit. A significant portion of the estimate is associated with the Asset Closure segment, thus related to closed facilities with changes in the estimate recorded to the statement of operations. Changes in these assumptions could have a significant impact on the carrying amount of the asset retirement obligations. The asset retirement obligation balance related to mining land reclamation obligations was $410 million as of December 31, 2019.

Given the complexity and the significant judgements made by management, including internally developed volumetric models to estimate the mining land reclamation asset retirement obligation, performing audit procedures to evaluate the reasonableness of management's estimates and assumptions required a high degree of auditor judgment and an increased extent of effort, including the need to involve our environmental specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the mining land reclamation obligation included the following, among others:

- We tested the effectiveness of controls over the accounting for asset retirement obligations, including those over management's development of cost estimates.
- We evaluated management's ability to accurately develop cost estimates by comparing actual results to management's prior cost estimates.
- We evaluated the completeness of management's cost estimates by comparing management's cost estimates to regulatory agency filings.
- With the assistance of our environmental specialists, we evaluated management's cost estimates by assessing the impact of any changes in the regulatory environment and testing the mathematical accuracy and reasonableness of management's volumetric model.
- We selected a sample of cost estimates for mining land reclamation and performed the following:
  - Evaluated management's cost estimates for mining land reclamation by performing corroborating inquiries with the Company's project managers and engineers and comparing the estimates to management's workplans, engineering specifications, and supplier contracts.
  - With the assistance of our environmental specialists, we evaluated the reasonableness of the costs estimates for mining land reclamation by:
    - Evaluating the reasonableness of the methodology used to develop the cost estimate.
    - Testing the source information underlying the determination of the cost estimates for mining land reclamation and the mathematical accuracy of the calculations.
  - Developed a range of independent estimates and compared those to the cost estimates developed by management.

Acquisitions, Merger Transaction and Business Combination Accounting — Crius Energy Trust — Retail Customer Relationship Intangible Asset — Refer to Notes 2 and 6 to the financial statements

Critical Audit Matter Description

The Company completed the acquisition of Crius Energy Trust for $400 million on July 15, 2019. The Company accounted for the acquisition under the acquisition method of accounting for business combinations. Accordingly, the purchase price was allocated to the assets acquired and liabilities assumed based on their respective fair values, including customer relationship intangible assets of $223 million. Management estimated the fair value of the customer relationship intangible asset using an income-based valuation methodology, specifically a discounted cash flow analysis. The fair value determination of the customer relationship intangible assets required management to make significant estimates and assumptions related to forecasted future cash flows, customer attrition rates and discount rates.

We identified the customer relationship intangible assets for the acquired entity as a critical audit matter because of the significant estimates and assumptions management made to estimate the fair value of these assets. This required a high degree of auditor judgment and an increased extent of effort, including the involvement of our fair value specialists, when performing audit procedures to evaluate the reasonableness of management's forecasts of future cash flows and the customer attrition rates and discount rates used in the valuation.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the forecasts of future cash flows and the customer attrition rates and discount rates used in valuing the customer relationship intangible assets for the acquired business included the following, among others:

- We tested the effectiveness of controls over the valuation of the customer relationship intangible assets, including management's controls over the development of the key judgments including forecasts of future cash flows and customer attrition rates and discount rates.

- We assessed the reasonableness of fiscal year 2019 forecasted cash flows by comparing them to the actual 2019 cash flows of the acquired business.

- We assessed the reasonableness of the forecasts of future cash flows by comparing margins and attrition rates to the acquired business' most recent historical periods.

- We performed sensitivity analyses of the significant assumptions of forecasted future cash flows, customer attrition rates, and discount rates used in the valuation model to evaluate the change in fair value resulting from changes in the significant assumptions.

- With the assistance of our fair value specialists, we evaluated the reasonableness of the (1) valuation methodology; (2) customer attrition rate by testing the mathematical accuracy of the rate used and comparing it to historical customer attrition data and actual customer attrition subsequent to the acquisition date; and (3) discount rate, which included testing the source information underlying the determination of the discount rates, testing the mathematical accuracy of the calculations, and developing a range of independent estimates and comparing those to the discount rates selected by management.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 28, 2020

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

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

	Year Ended December 31,		
	2019	2018	2017
Operating revenues (Note 5)	$ 11,809	$ 9,144	$ 5,430
Fuel, purchased power costs and delivery fees	(5,742)	(5,036)	(2,935)
Operating costs	(1,530)	(1,297)	(973)
Depreciation and amortization	(1,640)	(1,394)	(699)
Selling, general and administrative expenses	(904)	(926)	(600)
Impairment of long-lived assets	—	—	(25)
Operating income	1,993	491	198
Other income (Note 21)	56	47	37
Other deductions (Note 21)	(15)	(5)	(5)
Interest expense and related charges (Note 21)	(797)	(572)	(193)
Impacts of Tax Receivable Agreement (Note 8)	(37)	(79)	213
Equity in earnings of unconsolidated investment (Note 21)	16	17	—
Income (loss) before income taxes	1,216	(101)	250
Income tax (expense) benefit (Note 7)	(290)	45	(504)
Net income (loss)	926	(56)	(254)
Net loss attributable to noncontrolling interest	2	2	—
Net income (loss) attributable to Vistra Energy	$ 928	$ (54)	$ (254)
Weighted average shares of common stock outstanding:			
Basic	494,146,268	504,954,371	427,761,460
Diluted	499,935,490	504,954,371	427,761,460
Net income (loss) per weighted average share of common stock outstanding:			
Basic	$ 1.88	$ (0.11)	$ (0.59)
Diluted	$ 1.86	$ (0.11)	$ (0.59)

See Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Millions of Dollars)

	Year Ended December 31,		
	2019	2018	2017
Net income (loss)	$ 926	$ (56)	$ (254)
Other comprehensive income (loss), net of tax effects:			
Effects related to pension and other retirement benefit obligations (net of tax benefit of $4, $2 and $6)	(8)	(6)	(23)
Adoption of new accounting standard	—	1	—
Total other comprehensive income (loss)	(8)	(5)	(23)
Comprehensive income (loss)	918	(61)	(277)
Comprehensive loss attributable to noncontrolling interest	2	2	—
Comprehensive income (loss) attributable to Vistra Energy	$ 920	$ (59)	$ (277)

See Notes to the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2019	2018	2017
Cash flows — operating activities:			
Net income (loss)	$ 926	$ (56)	$ (254)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation and amortization	1,876	1,533	835
Deferred income tax expense (benefit), net	281	(62)	418
Unrealized net (gain) loss from mark-to-market valuations of commodities	(696)	380	145
Unrealized net (gain) loss from mark-to-market valuations of interest rate swaps	220	5	(29)
Impairment of long-lived assets (Note 4)	—	—	25
Impacts of Tax Receivable Agreement (Note 8)	37	79	(213)
Change in asset retirement obligation liability	(48)	(27)	112
Asset retirement obligation accretion expense	53	50	60
Bad debt expense	82	55	39
Stock-based compensation	47	73	—
Other, net	(12)	37	30
Changes in operating assets and liabilities:			
Accounts receivable — trade	(88)	(207)	7
Inventories	(44)	61	22
Accounts payable — trade	(221)	90	(30)
Commodity and other derivative contractual assets and liabilities	98	(80)	(1)
Margin deposits, net	170	(221)	146
Accrued interest	80	(105)	(10)
Accrued taxes	(4)	(64)	33
Accrued employee incentive	1	40	(24)
Alcoa contract settlement (Note 4)	—	—	238
Tax Receivable Agreement payment (Note 8)	(2)	(16)	(26)
ARO settlement	(121)	(100)	(35)
Major plant outage deferral	(19)	(22)	(66)
Other — net assets	(22)	73	4
Other — net liabilities	142	(45)	(40)
Cash provided by operating activities	2,736	1,471	1,386
Cash flows — investing activities:			
Capital expenditures, including LTSA prepayments	(520)	(378)	(114)
Nuclear fuel purchases	(89)	(118)	(62)
Development and growth expenditures (Note 3)	(104)	(34)	(190)
Ambit acquisition (net of cash acquired) (Note 2)	(506)	—	—
Crius acquisition (net of cash acquired) (Note 2)	(374)	—	—
Cash acquired in the Merger (Note 2)	—	445	—
Odessa acquisition (Note 3)	—	—	(355)
Proceeds from sales of nuclear decommissioning trust fund securities (Note 21)	431	252	252
Investments in nuclear decommissioning trust fund securities (Note 21)	(453)	(274)	(272)
Proceeds from sales of environmental allowances	197	1	1

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

	Year Ended December 31,		
	2019	2018	2017
Purchases of environmental allowances	(322)	(5)	(3)
Other, net	23	10	16
Cash used in investing activities	(1,717)	(101)	(727)
Cash flows — financing activities:			
Issuances of long-term debt (Note 11)	6,507	1,000	—
Repayments/repurchases of debt (Note 11)	(7,109)	(3,075)	(191)
Net borrowings under accounts receivable securitization program (Note 10)	111	339	—
Borrowings under Revolving Credit Facility (Note 11)	650	—	—
Repayments under Revolving Credit Facility (Note 11)	(300)	—	—
Debt tender offer and other debt financing fees (Note 11)	(203)	(236)	(8)
Stock repurchase (Note 14)	(656)	(763)	—
Dividends paid to stockholders (Note 14)	(243)	—	—
Other, net	6	12	(2)
Cash used in financing activities	(1,237)	(2,723)	(201)
Net change in cash, cash equivalents and restricted cash	(218)	(1,353)	458
Cash, cash equivalents and restricted cash — beginning balance	693	2,046	1,588
Cash, cash equivalents and restricted cash — ending balance	$ 475	$ 693	$ 2,046

See Notes to the Consolidated Financial Statements.

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

	Year Ended December 31, 2019	2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 300	$ 636
Restricted cash (Note 21)	147	57
Trade accounts receivable — net (Note 21)	1,365	1,087
Inventories (Note 21)	469	412
Commodity and other derivative contractual assets (Note 16)	1,333	730
Margin deposits related to commodity contracts	202	361
Prepaid expense and other current assets	298	152
Total current assets	4,114	3,435
Restricted cash (Note 21)	28	—
Investments (Note 21)	1,537	1,250
Investment in unconsolidated subsidiary (Note 21)	124	131
Operating lease right-of-use assets (Note 12)	44	—
Property, plant and equipment — net (Note 21)	13,914	14,612
Goodwill (Note 6)	2,553	2,068
Identifiable intangible assets — net (Note 6)	2,748	2,493
Commodity and other derivative contractual assets (Note 16)	136	109
Accumulated deferred income taxes (Note 7)	1,066	1,336
Other noncurrent assets	352	590
Total assets	$ 26,616	$ 26,024
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term borrowings (Note 11)	$ 350	$ —
Accounts receivable securitization program (Note 10)	450	339
Long-term debt due currently (Note 11)	277	191
Trade accounts payable	947	945
Commodity and other derivative contractual liabilities (Note 16)	1,529	1,376
Margin deposits related to commodity contracts	8	4
Accrued income taxes	1	10
Accrued taxes other than income	200	182
Accrued interest	151	77
Asset retirement obligations (Note 21)	141	156
Operating lease liabilities (Note 12)	14	—
Other current liabilities	506	345
Total current liabilities	4,574	3,625
Long-term debt, less amounts due currently (Note 11)	10,102	10,874
Operating lease liabilities (Note 12)	41	—
Commodity and other derivative contractual liabilities (Note 16)	396	270
Accumulated deferred income taxes (Note 7)	2	10
Tax Receivable Agreement obligation (Note 8)	455	420
Asset retirement obligations (Note 21)	2,097	2,217
Other noncurrent liabilities and deferred credits (Note 21)	989	741
Total liabilities	18,656	18,157

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

	Year Ended December 31,	
	2019	**2018**
Commitments and Contingencies (Note 13)		
Total equity (Note 14):		
Common stock (par value — $0.01; number of shares authorized — 1,800,000,000) (shares outstanding: December 31, 2019 — 487,698,111; December 31, 2018 — 493,215,309)	5	5
Treasury stock, at cost (shares: December 31, 2019 — 41,043,224; December 31, 2018 — 32,815,783)	(973)	(778)
Additional paid-in-capital	9,721	10,107
Retained deficit	(764)	(1,449)
Accumulated other comprehensive income (loss)	(30)	(22)
Stockholders' equity	7,959	7,863
Noncontrolling interest in subsidiary	1	4
Total equity	7,960	7,867
Total liabilities and equity	$ 26,616	$ 26,024

See Notes to the Consolidated Financial Statements.

VISTRA ENERGY CORP.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Millions of Dollars)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interest in Subsidiary	Total Equity
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
Stock repurchases	—	(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	—	—	—	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	$ (778)	$10,107	$(1,449)	$ (22)	$ 7,863	$ 4	$ 7,867
Stock repurchases	—	(641)	—	—	—	(641)	—	(641)
Shares issued for tangible equity unit contracts	—	446	(446)	—	—	—	—	—
Effects of stock-based compensation	—	—	62	—	—	62	—	62
Net income (loss)	—	—	—	928	—	928	(2)	926
Dividends declared on common stock	—	—	—	(243)	—	(243)	—	(243)
Adoption of new accounting standard	—	—	—	(2)	—	(2)	—	(2)
Pension and OPEB liability — change in funded status	—	—	—	—	(8)	(8)	—	(8)
Other	—	—	(2)	2	—	—	(1)	(1)
Balances at December 31, 2019	$ 5	$ (973)	$ 9,721	$ (764)	$ (30)	$ 7,959	$ 1	$ 7,960

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, as apparent in the context. See *Glossary* for defined terms.

Vistra Energy is a holding company operating an integrated retail and generation business primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and natural gas 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 20 for further information concerning reportable business segments.

Ambit Transaction

On November 1, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the acquisition of Ambit (Ambit Transaction). Because the Ambit Transaction closed on November 1, 2019, Vistra Energy's consolidated financial statements and the notes related thereto do not include the financial condition or the operating results of Ambit and its subsidiaries prior to November 1, 2019. See Note 2 for a summary of the Ambit Transaction.

Crius Transaction

On July 15, 2019, an indirect, wholly owned subsidiary of Vistra Energy completed the acquisition of the equity interests of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius (Crius Transaction). Because the Crius Transaction closed on July 15, 2019, Vistra Energy's consolidated financial statements and the notes related thereto do not include the financial condition or the operating results of Crius and its subsidiaries prior to July 15, 2019. See Note 2 for a summary of the Crius Transaction.

Dynegy 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

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 2018 Form 10-K. 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, judgments 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 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 15 and 16 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, 2019 and 2018, there were no derivative positions accounted for as cash flow or fair value hedges.

We report commodity hedging and trading results as revenue, fuel expense or purchased power in the consolidated statements of operations 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. Realized and unrealized gains and losses associated with interest rate swap transactions are reported in the consolidated statements of operations in interest expense.

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.

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 5 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 SG&A expenses. Advertising expenses totaled $49 million, $46 million and $44 million for the year ended December 31, 2019, 2018 and 2017, 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 6 for details of intangible assets with finite 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 and liabilities, identifiable intangible assets and liabilities, then any remaining excess reorganization value is allocated to goodwill. 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. See Note 6 for details of goodwill and intangible assets with indefinite lives, 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 consolidated statements of operations.

Major Maintenance Costs

Major maintenance costs incurred 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 consolidated statements of operations.

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.

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.

See Note 17 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 18 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 consolidated statements of operations (*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 in other current liabilities in our consolidated statements of operations).

Franchise and Revenue-Based Taxes

Unlike sales and excise taxes, franchise and gross receipt taxes are not "pass through" items. 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 consolidated statements of operations.

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 $4.5 billion of utilizable NOLs and refundable AMT tax credits.

Investment tax credits are accounted for under the deferral method, which resulted in a reduction to the basis of the Upton 2 solar and battery storage facility of $2 million and $78 million and a corresponding increase in the deferred tax assets in 2019 and 2018, respectively.

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 7.

We report interest and penalties related to uncertain tax positions as current income tax expense. See Note 7.

Tax Receivable Agreement (TRA)

The Company accounts for its obligations under the TRA as a liability in our consolidated balance sheets (see Note 8). 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 and state corporate income tax rates 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 consolidated statements of operations 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 13 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 Note 21 for more details regarding restricted cash.

Property, Plant and Equipment

Property, plant and equipment 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 21.

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 21.

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 recorded as operating costs in the consolidated statements of operations. See Note 21.

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 21.

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 21 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 consolidated statements of operations. See Note 21.

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 14.

Leases

At the inception of a contract we determine if it is or contains a lease, which involves the contract conveying the right to control the use of explicitly or implicitly identified property, plant, or equipment for a period of time in exchange for consideration.

Right-of-use (ROU) assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. ROU assets and lease liabilities are recognized at the commencement date of the underlying lease based on the present value of lease payments over the lease term. We use our secured incremental borrowing rate based on the information available at the lease commencement date to determine the present value of lease payments. Operating leases are included in operating lease ROU assets, operating lease liabilities (current) and operating lease liabilities (noncurrent) on our consolidated balance sheet. Finance leases are included in property, plant and equipment, other current liabilities and other noncurrent liabilities and deferred credits on our consolidated balance sheet. Lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise the option. At adoption, we elected the practical expedient which permits us to not reassess under the new standard our prior conclusion about lease classification and initial direct costs. We have also elected the practical expedient to not separate lease and non-lease components for a majority of the lease asset classes. We have also elected the hindsight practical expedient to determine the lease term.

Leases with an initial lease term of 12 months or less are not recorded on the balance sheet; we recognize lease expense for these leases on a straight-line basis over the lease term.

We also present lessor sublease income on a net basis against the related lessee lease expense.

Adoption of New Accounting Standards

Leases — On January 1, 2019, we adopted Accounting Standards Update (ASU) 2016-02, *Leases (Topic 842)* and all related amendments (new lease standard) using the modified retrospective method with the cumulative-effect adjustment to the opening balance of retained deficit for all contracts outstanding at the time of adoption. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. We expect the impact of the adoption of the new lease standard to be immaterial to our net income on an ongoing basis. The impact of adopting the new lease standard primarily relates to recognition of lease liabilities and ROU assets for all leases classified as operating leases. Under the new lease standard, each ROU asset will be amortized over the lease term and liability settled at the end of the lease term.

We recognized the effect of initially applying the new lease standard by recording ROU assets of $85 million and lease liabilities of $123 million in our consolidated balance sheet.

As of January 1, 2019, the cumulative effect of the changes made to our consolidated balance sheet for the adoption of the new lease standard was as follows:

	December 31, 2018	Adoption of New Lease Standard	January 1, 2019
Impact on consolidated balance sheet:			
Assets			
Property, plant and equipment — net	$ 14,612	$ 15	$ 14,627
Operating lease right-of-use assets	—	70	70
Prepaid expense and other current assets	152	(2)	150
Accumulated deferred income taxes	1,336	1	1,337
Liabilities			
Other current liabilities	345	(1)	344
Operating lease liabilities	—	109	109
Identifiable intangible liabilities	401	(36)	365
Other noncurrent liabilities and deferred credits	340	14	354
Equity			
Retained deficit	(1,449)	(2)	(1,451)

See Note 12 for the disclosures required by the new lease standard.

Changes to the Disclosure Requirements for Defined Benefit Plans — In August 2018, the Financial Accounting Standards Board (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 17.

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 TCJA 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 deficit (see Note 7).

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 revenue standard as an adjustment to the opening balance of retained deficit. 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 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 revenue standard primarily relates to the deferral of acquisition costs associated with retail contracts with customers that were previously expensed as incurred. Under the revenue standard, these amounts are capitalized and amortized over the expected life of the customer.

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 consolidated statements of cash flows, and retrospective application to comparative periods presented was required. For the year ended December 31, 2017, our consolidated statements of cash flows previously reflected a source of cash of $186 million, reported as changes in restricted cash, that is now reported in net change in cash, cash equivalents and restricted cash. See the consolidated statements of cash flows and Note 21 for disclosures related to the adoption of this accounting standard.

Changes in Accounting Standards

In December 2019, the FASB issued ASU 2019-12, *Simplifying the Accounting for Income Taxes (Topic 740)*. The ASU will be effective for fiscal years beginning after December 15, 2020 and early adoption is permitted. The ASU enhances and simplifies various aspects of the income tax accounting guidance including the elimination of certain exceptions related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. The new guidance also simplifies aspects of the accounting for franchise taxes and enacted changes in tax laws or rates and clarifies the accounting for transactions that result in a step-up in the tax basis of goodwill. We are currently evaluating the impact of this ASU on our financial statements, but we do not expect it to have a material impact upon adoption.

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 do not expect the ASU to have a material impact on our financial statements.

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 do not expect the ASU to have a material impact on our financial statements.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses*. The ASU requires organizations to measure all expected credit losses for financial instruments held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. The ASU will be effective for fiscal years beginning after December 31, 2019. We do not expect the ASU to have a material impact on our financial statements.

2. ACQUISITIONS, MERGER TRANSACTION AND BUSINESS COMBINATION ACCOUNTING

Ambit Transaction

On November 1, 2019 (Ambit Acquisition Date), Volt Asset Company, Inc., an indirect, wholly owned subsidiary of Vistra Energy, completed the Ambit Transaction. Ambit is an energy retailer selling both electricity and natural gas products to residential and small business customers in 17 states. Vistra Energy funded the purchase price of $555 million (including cash acquired and net working capital) using cash on hand. All of Ambit's outstanding debt was repaid from the purchase price at closing and not assumed by Vistra Energy.

Crius Transaction

On July 15, 2019 (Crius Acquisition Date), Vienna Acquisition B.C. Ltd., an indirect, wholly owned subsidiary of Vistra Energy, completed the acquisition of the equity interests of two wholly owned subsidiaries of Crius that indirectly own the operating business of Crius. Crius is an energy retailer selling both electricity and natural gas products to residential and small business customers in 19 states. Vistra Energy funded the purchase price of $400 million (including $382 million for outstanding trust units) using cash on hand. See Note 11 for discussion of debt assumed in the Crius Transaction.

Ambit and Crius Business Combination Accounting

We believe the Ambit Transaction has (i) augmented Vistra Energy's existing retail marketing capabilities with additional direct selling capability and a proprietary technology platform, (ii) reduced risk and aided expansion into higher margin channels by improving Vistra Energy's match of its generation to load profile due to a high degree of overlap with Vistra Energy's generation fleet with Ambit's approximately 11 TWh of annual load, primarily in ERCOT and PJM and (iii) enhanced the integrated value proposition through collateral and transaction efficiencies, particularly via Ambit's retail electric portfolio.

We believe the Crius Transaction has (i) reduced risk and aided expansion into higher margin channels by improving Vistra Energy's match of its generation to load profile due to a high degree of overlap with Vistra Energy's generation fleet with Crius' approximately 10 TWh of annual electricity load, (ii) established a platform for growth by leveraging Vistra Energy's existing retail marketing capabilities and Crius' experienced team and (iii) enhanced the integrated value proposition through collateral and transaction efficiencies, particularly via Crius' retail electric portfolio.

The Ambit and Crius Transactions are 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 Ambit and Crius Acquisition Dates, respectively. The combined results of operations are reported in our consolidated financial statements beginning as of the respective Ambit and Crius Acquisition Dates. A summary of the techniques used to estimate the fair value of the identifiable assets and liabilities, as well as their classification within the fair value hierarchy (see Note 15), is listed below:

- Working capital was valued using available market information (Level 2).
- Acquired derivatives were valued using the methods described in Note 15 (Level 2 or Level 3).
- Acquired retail customer relationship was valued based on discounted cash flow analysis of acquired customers and estimated attrition rates (Level 3).
- Crius' long-term debt was valued using a market approach (Level 2).

The following table summarizes the preliminary allocation of the purchase price to the fair value amounts recognized for the assets acquired and liabilities assumed related to the Ambit and Crius Transactions as of the Ambit and Crius Acquisition Dates, respectively. The Ambit Transaction purchase price was $555 million (including cash acquired and net working capital), and the Crius Transaction purchase price was $400 million. The purchase price allocations are ongoing and are dependent upon final valuation determinations, which have not been completed. The preliminary values included below represent our current best estimates for accumulated deferred income taxes, identifiable intangible assets, net working capital and long-term debt. During the three months ended December 31, 2019, we updated the preliminary purchase price allocation of the Crius Transaction reported as of September 30, 2019 with revised valuation estimates by decreasing net working capital by $37 million, decreasing identifiable intangible assets by $2 million, increasing goodwill by $52 million, decreasing other noncurrent assets by $2 million, decreasing identifiable intangible liabilities by $36 million, increasing other noncurrent liabilities and deferred credits by $1 million and changing accumulated deferred income taxes from an asset of $36 million to a liability of $9 million. The purchase price allocations are preliminary and each of the values included below may change materially based upon the receipt of more detailed information, additional analyses and completed valuations. The final purchase price allocation is expected to be completed no later than the second quarter of 2020 for the Crius Transaction and no later than the third quarter of 2020 for the Ambit Transaction.

Ambit and Crius Transactions Preliminary Purchase Price Allocations

	Ambit Transaction	Crius Transaction
Cash and cash equivalents and restricted cash	$ 49	$ 26
Net working capital	29	(4)
Identifiable intangible assets	263	292
Goodwill	214	257
Commodity and other derivative contractual assets	23	18
Other noncurrent assets	13	18
Total assets and net working capital acquired	591	607
Long-term debt, including amounts due currently	—	141
Commodity and other derivative contractual liabilities	28	40
Accumulated deferred income taxes	—	9
Other noncurrent liabilities and deferred credits	8	17
Total liabilities assumed	36	207
Identifiable net assets acquired	$ 555	$ 400

In the year ended December 31, 2019, acquisition costs incurred in the Ambit and Crius Transactions totaled $1 million and $2 million, respectively. For the Ambit Acquisition Date through December 31, 2019, our consolidated statements of operations include revenues and net income acquired in the Ambit Transaction totaling $193 million and $2 million, respectively. For the Crius Acquisition Date through December 31, 2019, our consolidated statements of operations include revenues and net income acquired in the Crius Transaction totaling $453 million and zero, respectively. The net income acquired in the Ambit and Crius Transactions include intangible amortization and transition related expenses.

Ambit and Crius Transaction Unaudited Pro Forma Financial Information — The following unaudited consolidated pro forma financial information for the years ended December 31, 2019 and 2018 assumes that the Ambit and Crius Transactions occurred on January 1, 2018 (i.e., represents our results for the years ended December 31, 2019 and 2018 plus the results for either Ambit or Crius for the period not owned by us, respectively). The unaudited consolidated pro forma financial information is provided for informational purposes only and is not necessarily indicative of the results of operations that would have occurred had the Ambit and Crius Transactions been completed on January 1, 2018, nor is the unaudited consolidated pro forma financial information indicative of future results of operations, which may differ materially from the consolidated pro forma financial information presented here.

	Ambit Transaction		Crius Transaction	
	Year Ended December 31,		Year Ended December 31,	
	2019	2018	2019	2018
Revenues	$ 12,931	$ 10,446	$ 12,373	$ 10,379
Net income (loss) (a)	$ 949	$ (95)	$ 876	$ (43)
Net income (loss) attributable to Vistra Energy	$ 951	$ (93)	$ 878	$ (41)
Net income (loss) attributable to Vistra Energy per weighted average share of common stock outstanding — basic	$ 1.92	$ (0.18)	$ 1.78	$ (0.08)
Net income (loss) attributable to Vistra Energy per weighted average share of common stock outstanding — diluted	$ 1.90	$ (0.18)	$ 1.76	$ (0.08)

(a) Decrease in pro forma net income compared to consolidated net income is driven by unrealized losses on hedging activities of Crius and amortization of intangible assets.

The consolidated 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 and the related impacts on tax expense.

Dynegy 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. The Merger was 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 would 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.

Dynegy Business Combination Accounting

We believe the Merger has provided and continues to provide significant strategic benefits and opportunities to Vistra Energy, including increased scale and market diversification, rebalanced asset portfolio and improved earnings and cash flow. The Merger 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 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 fair value of the identifiable assets and liabilities, as well as their classification within the fair value hierarchy (see Note 15), 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 15 (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 final 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. During the three months ended March 31, 2019, the purchase price allocation was completed. During the period from April 9, 2018 through March 31, 2019, we updated the initial purchase price allocation with final valuations by increasing property, plant and equipment by $173 million, decreasing intangible assets by $36 million, increasing goodwill by $175 million, decreasing accounts receivable, inventory, prepaid expenses and other current assets by $10 million, increasing accumulated deferred tax asset by $127 million, decreasing other noncurrent assets by $113 million, increasing trade accounts payable and other current liabilities by $89 million, increasing other noncurrent liabilities by $177 million, increasing asset retirement obligations, including amounts due currently by $56 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.

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

Dynegy Merger Final Purchase Price Allocation

Cash and cash equivalents	$	445
Trade accounts receivables, inventories, prepaid expenses and other current assets		853
Property, plant and equipment		10,535
Accumulated deferred income taxes		518
Identifiable intangible assets		351
Goodwill		175
Other noncurrent assets		419
Total assets acquired		13,296
Trade accounts payable and other current liabilities		733
Commodity and other derivative contractual assets and liabilities, net		422
Asset retirement obligations, including amounts due currently		475
Long-term debt, including amounts due currently		8,919
Other noncurrent liabilities		469
Total liabilities assumed		11,018
Identifiable net assets acquired		2,278
Noncontrolling interest in subsidiary		5
Total purchase price	$	2,273

Acquisition costs incurred in the Merger totaled less than $1 million and $25 million for the years ended December 31, 2019 and 2018, respectively. For the period from the Merger Date through December 31, 2018, our consolidated statements of operations include revenues and net income (loss) acquired in the Merger totaling $3.902 billion and $224 million respectively.

Dynegy Merger 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 informational 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

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

Oakland — In June 2019, East Bay Community Energy signed a ten-year contract to receive resource adequacy capacity from the planned development of a 20 MW battery ESS at our Oakland Power Plant site in California. The contract is pending a concurrent utility Market Capability Agreement contract for review and signature. The utility Market Capability Agreement will then be sent to the California Public Utilities Commission (CPUC) for approval.

Moss Landing — In June 2018, we announced that, subject to approval by the CPUC, we would enter into a 20-year resource adequacy contract with Pacific Gas and Electric Company (PG&E) to develop a 300 MW battery ESS at our Moss Landing Power Plant site in California. PG&E filed its application with the CPUC in June 2018 and the CPUC approved the resource adequacy contract in November 2018. At December 31, 2019, we had accumulated approximately $64 million in construction work-in-process for this ESS. Under the contract, PG&E will pay us a fixed monthly resource adequacy payment, while we will receive the energy revenues and incur the costs from dispatching and charging the ESS. We anticipate the Moss Landing battery ESS will commence commercial operations in the fourth quarter of 2020. PG&E filed for Chapter 11 bankruptcy protection in January 2019. On October 15, 2019, PG&E filed a motion in its bankruptcy proceeding requesting approval of the assumption of the resource adequacy contract. In early November, the bankruptcy court approved the assumption motion subject to the CPUC approving the terms of the amendment. The CPUC approved the terms of the amendment on January 22, 2020 so the resource adequacy contract as amended is now assumed and fully enforceable against PG&E.

Solar Development Project

Upton 2 — 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 into a turnkey engineering, procurement and construction agreement to construct the approximately 180 MW facility. 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.

Odessa Acquisition

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.

4. RETIREMENT OF GENERATION FACILITIES

MISO — In September 2019, we announced the settlement of a lawsuit alleging violations of opacity and particulate matter limits at our Edwards facility in Bartonville, Illinois. As part of the settlement, which was approved by the court in November 2019, we will retire the Edwards facility by the end of 2022 (see Note 13). In August 2019, we announced the planned retirement of four power plants in Illinois with a total installed nameplate generation capacity of 2,068 MW. We retired these units due to changes in the Illinois multi-pollutant standard rule that require us to retire approximately 2,000 MW of generation capacity (see Note 13). In light of the provisions of the Federal Power Act and the FERC regulations thereunder, the affected subsidiaries of Vistra Energy identified the retired units by analyzing the economics of each of our Illinois plants and designating the least economic units for retirement. Expected plant retirement expenses of $47 million, driven by severance costs, were accrued in the year ended December 31, 2019 and are included primarily in operating costs of our Asset Closure segment. In August 2019, we remeasured our pension and OPEB plans resulting in an increase to the benefit obligation liability of $21 million, pretax other comprehensive loss of $18 million and curtailment expense of $3 million recognized as other deductions in our consolidated statements of operations. The following table details the units that have been or will be retired in Illinois totaling 2,653 MW. Operational results for retired plants are included in the Asset Closure segment, which is engaged in the decommissioning and reclamation of retired plants and mines.

Name	Location (all in the state of Illinois)	Fuel Type	Net Generation Capacity (MW)	Number of Units	Dates Units Taken Offline
Coffeen	Coffeen, IL	Coal	915	2	November 1, 2019
Duck Creek	Canton, IL	Coal	425	1	December 15, 2019
Havana	Havana, IL	Coal	434	1	November 1, 2019
Hennepin	Hennepin, IL	Coal	294	2	November 1, 2019
Edwards	Bartonville, IL	Coal	585	2	By the end of 2022
Total			2,653	8	

PJM — 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 Power Company waste coal facility in McAdoo, Pennsylvania (Northeastern Facility). We decided to retire the Northeastern Facility due to its uneconomic operations and financial outlook. Following the receipt of regulatory approvals, the Northeastern Facility was retired in October 2018. The decision to retire the Northeastern Facility did not result in a material impact to the financial statements, and the operational results of the Northeastern 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		

ERCOT — In January and February 2018, we retired three power plants in Texas 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 of 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	

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 consolidated statements of operations. 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.

5. REVENUE

The following tables disaggregate our revenue by major source:

	Year Ended December 31, 2019							
	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	CAISO/ Eliminations	Consolidated
Revenue from contracts with customers:								
Retail energy charge in ERCOT	$ 4,983	$ —	$ —	$ —	$ —	$ —	$ —	$ 4,983
Retail energy charge in Northeast/ Midwest	1,818	—	—	—	—	—	—	1,818
Wholesale generation revenue from ISO/RTO	—	1,629	579	434	215	194	193	3,244
Capacity revenue	—	—	162	181	24	11	—	378
Revenue from other wholesale contracts	—	264	521	181	147	2	9	1,124
Total revenue from contracts with customers	6,801	1,893	1,262	796	386	207	202	11,547
Other revenues:								
Intangible amortization	(15)	—	—	(4)	(17)	—	4	(32)
Hedging and other revenues (a)	86	(245)	105	162	12	42	132	294
Affiliate sales	—	2,345	1,075	181	277	92	(3,970)	—
Total other revenues	71	2,100	1,180	339	272	134	(3,834)	262
Total revenues	$ 6,872	$ 3,993	$ 2,442	$ 1,135	$ 658	$ 341	$ (3,632)	$ 11,809

(a) Includes $682 million of unrealized net gains from mark-to-market valuations of commodity positions. See Note 20 for unrealized net gains (losses) by segment.

	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	254	218	167	3,126
Capacity revenue	—	—	369	240	25	34	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	412	252	203	9,797
Other revenues:								
Intangible amortization	(26)	(1)	2	(9)	(9)	—	—	(43)
Hedging and other revenues (a)	74	(362)	(62)	(41)	(120)	(106)	7	(610)
Affiliate sales	—	1,632	595	41	116	225	(2,609)	—
Total other revenues	48	1,269	535	(9)	(13)	119	(2,602)	(653)
Total revenues	$ 5,597	$ 2,634	$ 1,725	$ 817	$ 399	$ 371	$ (2,399)	$ 9,144

(a) Includes $380 million of unrealized net losses from mark-to-market valuations of commodity positions. See Note 20 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. When electricity is sold to and purchased from the same ISO or RTO in the same period, the excess of the amount sold over the amount purchased is reflected in wholesale generation revenues.

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 ISO or RTO, 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, is 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, 2019 and 2018 and January 1, 2018 was $53 million, $38 million and $22 million, respectively. The amortization related to these costs during the year ended December 31, 2019 and 2018 totaled $21 million and $10 million, respectively, recorded as SG&A expenses, and $9 million and $7 million, respectively, recorded as a reduction to operating revenues in the consolidated statements of operations.

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 have elected to 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, 2019, 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 $784 million, $732 million, $426 million, $96 million and $29 million that will be recognized in the years ending December 31, 2020, 2021, 2022, 2023 and 2024, respectively, and $47 million thereafter. Capacity revenues are recognized as capacity is made available 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, 2019	December 31, 2018
Trade accounts receivable from contracts with customers — net	$ 1,246	$ 951
Other trade accounts receivable — net	119	136
Total trade accounts receivable — net	$ 1,365	$ 1,087

(a) At December 31, 2019, includes $175 million of trade accounts receivable related to operations acquired in the Ambit and Crius Transactions.

6. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS AND LIABILITIES

Goodwill

The following table provides information regarding our goodwill balance. There have been no impairments of goodwill since Emergence.

Balance at December 31, 2016 and 2017 (a)	$ 1,907
Goodwill recorded in connection with the Merger (b)	161
Balance at December 31, 2018	2,068
Goodwill recorded in connection with the Merger (b)	14
Goodwill recorded in connection with the Crius Transaction (c)	257
Goodwill recorded in connection with the Ambit Transaction (c)	214
Balance at December 31, 2019	$ 2,553

(a) Goodwill totaling $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. Of the goodwill recorded at Emergence, $1.686 billion is deductible for tax purposes over 15 years on a straight-line basis.
(b) Goodwill totaling $175 million arose in connection with the Merger, of which $122 million is recorded in our ERCOT Generation reporting unit and $53 million is recorded in our ERCOT Retail reporting unit (see Note 2).
(c) Preliminary goodwill arising in connection with the Ambit and Crius Transactions is unassigned to a reporting unit pending completion of the purchase price allocations. None of the goodwill related to the Crius Transaction is deductible for tax purposes. The goodwill related to the Ambit Transaction of $214 million 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 Generation and ERCOT Retail reporting units exceeded their carrying value at October 1, 2019. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, cost factors, customer attrition, and changes in reporting unit book value.

Identifiable Intangible Assets and Liabilities

Identifiable intangible assets are comprised of the following:

	December 31, 2019			December 31, 2018		
Identifiable Intangible Asset	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Retail customer relationship	$ 2,078	$ 1,151	$ 927	$ 1,680	$ 876	$ 804
Software and other technology-related assets	341	125	216	270	105	165
Retail and wholesale contracts	315	182	133	316	138	178
Contractual service agreements (a)	59	5	54	70	—	70
Other identifiable intangible assets (b)	40	15	25	42	15	27
Total identifiable intangible assets subject to amortization	$ 2,833	$ 1,478	1,355	$ 2,378	$ 1,134	1,244
Retail trade names (not subject to amortization)			1,391			1,245
Mineral interests (not currently subject to amortization)			2			4
Total identifiable intangible assets			$ 2,748			$ 2,493

(a) At December 31, 2019, amounts related to contractual service agreements that have become liabilities due to amortization of the economic impacts of the intangibles have been removed from both the gross carrying amount and accumulated amortization.

(b) Includes mining development costs and environmental allowances (emissions allowances and renewable energy certificates).

Identifiable intangible liabilities are comprised of the following:

	Year Ended December 31,	
Identifiable Intangible Liability	2019	2018
Contractual service agreements	$ 110	$ 136
Purchase and sale of power and capacity	100	114
Fuel and transportation purchase contracts	76	81
Environmental allowances	—	70
Total identifiable intangible liabilities	$ 286	$ 401

Expense related to finite-lived identifiable intangible assets and liabilities (including the classification in the consolidated statements of operations) consisted of:

Identifiable Intangible Assets and Liabilities	Consolidated Statements of Operations	Remaining useful lives of identifiable intangible assets at December 31, 2019 (weighted average in years)	Year Ended December 31, 2019	2018	2017
Retail customer relationship	Depreciation and amortization	4	$ 275	$ 304	$ 420
Software and other technology-related assets	Depreciation and amortization	4	61	62	38
Retail and wholesale contracts/purchase and sale/fuel and transportation contracts	Operating revenues/fuel, purchased power costs and delivery fees	4	23	43	59
Other identifiable intangible assets	Operating revenues/fuel, purchased power costs and delivery fees/depreciation and amortization	4	148	58	15
Total intangible assets expense (a)			$ 507	$ 467	$ 532

(a) Amounts recorded in depreciation and amortization totaled \$340 million, \$370 million and \$463 million for the years ended December 31, 2019, 2018 and 2017 respectively. Amounts exclude contractual services agreements. Amounts include all expenses associated with environmental allowances including expenses accrued to comply with emissions allowance programs and renewable portfolio standards which are presented in fuel, purchased power costs and delivery fees on our consolidated statements of operations. Emissions allowance obligations are accrued as associated electricity is generated and renewable energy credit obligations are accrued as retail electricity delivery occurs.

The following is a description of the separately identifiable intangible assets. In connection with fresh start reporting, the Merger, the Crius Transaction and the Ambit Transaction, the intangible assets were adjusted based on their estimated fair value as of the Effective Date, the Merger Date, the Crius Acquisition Date and the Ambit Acquisition Date, respectively, based on observable prices or estimates of fair value using valuation models. The purchase price allocation for the Crius Transaction and the Ambit Transaction are 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 second quarter of 2020 for the Crius Transaction and the third quarter of 2020 for the Ambit Transaction.

- *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, Dynegy Energy Services, TriEagle Energy, U.S. Gas & Electric, Public Power and Ambit Energy 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, 2019.

- *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, the Merger Date, the Crius Acquisition Date or the Ambit Acquisition 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, 2019, 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	
2020	$	356
2021	$	255
2022	$	165
2023	$	119
2024	$	81

7. INCOME TAXES

Vistra Energy files a U.S. 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 U.S. Department of the 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.

Income Tax Expense (Benefit)

The components of our income tax expense (benefit) are as follows:

	Year Ended December 31,		
	2019	2018	2017
Current:			
U.S. Federal	$ (1)	$ (13)	$ 72
State	10	30	14
Total current	9	17	86
Deferred:			
U.S. Federal	260	(8)	417
State	21	(54)	1
Total deferred	281	(62)	418
Total	$ 290	$ (45)	$ 504

Reconciliation of income taxes computed at the U.S. federal statutory rate to income tax expense (benefit) recorded:

	Year Ended December 31,		
	2019	2018	2017
Income (loss) before income taxes	$ 1,216	$ (101)	$ 250
US federal statutory rate	21 %	21 %	35 %
Income taxes at the U.S. federal statutory rate	255	(20)	88
Nondeductible TRA accretion	5	8	(80)
State tax, net of federal benefit	48	22	13
Impacts of tax reform legislation on deferred taxes	—	—	451
Federal and State return to provision adjustment	(17)	(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	3	8	—
Nondeductible transaction costs	2	3	—
Equity awards	(4)	(3)	—
Valuation allowance on state NOLs	13	20	—
Lignite depletion	(6)	—	—
Texas gross margin amended return	(3)	—	—
Other	(6)	(2)	13
Income tax expense (benefit)	$ 290	$ (45)	$ 504
Effective tax rate	23.8 %	44.6 %	201.6 %

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2019 and 2018 are as follows:

	December 31,	
	2019	2018
Noncurrent Deferred Income Tax Assets		
Tax credit carryforwards	$ 73	$ 76
Loss carryforwards	921	958
Identifiable intangible assets	214	184
Long-term debt	257	188
Employee benefit obligations	112	109
Commodity contracts and interest rate swaps	108	212
Other	43	40
Total deferred tax assets	$ 1,728	$ 1,767
Noncurrent Deferred Income Tax Liabilities		
Property, plant and equipment	554	406
Total deferred tax liabilities	554	406
Valuation allowance	110	35
Net Deferred Income Tax Asset	$ 1,064	$ 1,326

At December 31, 2019, we had total deferred tax assets of approximately $1.064 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, 2019, 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 $13 million on the net operating loss carryforwards related to Illinois due to forecasted expiration. In addition, we recognized additional state NOLs that have a valuation allowance of $58 million through the Dynegy acquisition and $4 million through the Crius acquisition, which has no impact on our effective tax rate.

At December 31, 2019, we had $3.2 billion pre-tax net operating loss (NOL) carryforwards for federal income tax purposes that will begin to expire in 2032. At December 31, 2019, we had $164 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 $3 million and $2 million at December 31, 2019 and 2018, respectively.

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 for the years ended December 31, 2019, 2018 and 2017. 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 for the years ended December 31, 2019 and 2018. We did not have uncertain tax positions or uncertain tax position activity in the year ended December 31, 2017.

	Year Ended December 31,	
	2019	2018
Balance at beginning of period, excluding interest and penalties	$ 39	$ —
Additions allocated in the Merger	—	39
Additions based on tax positions related to prior years	3	—
Reductions based on tax positions related to prior years	—	—
Additions based on tax positions related to the current year	87	—
Settlements with taxing authorities	(3)	—
Balance at end of period, excluding interest and penalties	$ 126	$ 39

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, although review of Dynegy tax year 2018 continues to progress through the IRS's Compliance Assurance Process audit program. Crius is currently under audit by the IRS for the tax years 2015, 2016 and 2017. Uncertain tax positions totaling $126 million at December 31, 2019 reflect the addition of a $87 million reserve related to the deductibility of certain interest on Vistra Energy's 2018 federal and state tax returns under IRC Section 163(j). Vistra Energy's tax return positions reflect the approach likely taken in revised U.S. Department of the Treasury guidance expected to be forthcoming in the first half of 2020. We recorded a reserve for financial reporting purposes to reflect the U.S. Department of the Treasury's original proposed regulations under Section 163(j). Vistra Energy will reevaluate this reserve at the time new guidance is issued, which is currently expected in the first quarter of 2020. 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.

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.

8. 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 TCEH. 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 TCEH 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 19).

During the year ended December 31, 2019, we recorded a decrease to the carrying value of the TRA obligation totaling approximately $22 million as a result of adjustments to the timing of forecasted taxable income and state apportionment due to the expansion of Vistra Energy's state income tax profile, including Dynegy, Crius and Ambit acquisitions. 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, 2019, 2018 and 2017.

	Year Ended December 31,		
	2019	2018	2017
TRA obligation at the beginning of the period	$ 420	$ 357	$ 596
Accretion expense	59	65	82
Changes in tax assumptions impacting timing of payments	(22)	14	(62)
Revaluation due to tax reform legislation	—	—	(233)
Impacts of Tax Receivable Agreement	37	79	(213)
Payments	(2)	(16)	(26)
TRA obligation at the end of the period	455	420	357
Less amounts due currently	—	—	(24)
Noncurrent TRA obligation at the end of the period	$ 455	$ 420	$ 333

As of December 31, 2019, the estimated carrying value of the TRA obligation totaled $455 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 2019 and 2018 and 35% for 2017, (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, 2019, 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.

9. EARNINGS PER SHARE

Basic earnings per share available to common stockholders 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.

	Year Ended December 31,		
	2019	2018	2017
Net income (loss) attributable to common stock — basic	$ 928	$ (54)	$ (254)
Weighted average shares of common stock outstanding — basic	494,146,268	504,954,371	427,761,460
Net income (loss) per weighted average share of common stock outstanding — basic	$ 1.88	$ (0.11)	$ (0.59)
Dilutive securities: Stock-based incentive compensation plan	5,789,223	—	—
Weighted average shares of common stock outstanding — diluted	499,935,490	504,954,371	427,761,460
Net income (loss) per weighted average share of common stock outstanding — diluted	$ 1.86	$ (0.11)	$ (0.59)

Stock-based incentive compensation plan awards excluded from the calculation of diluted earnings per share because the effect would have been antidilutive totaled 2,447,850, 14,165,813 and 3,642,844 shares for the years ended December 31, 2019, 2018 and 2017, respectively.

10. 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 was renewed in July 2019, extending its scheduled termination from August 2019 to July 2020, with the ability to borrow up to $600 million up to the settlement date in November 2019, after which the amount available for RecCo reverted to $450 million. The agreement was subsequently amended to allow for a one-time, $560 million borrowing in November 2019 to take advantage of a seasonally-high receivable balance. The borrowing limit returned to $450 million thereafter.

Under the Receivables Facility, TXU Energy and Dynegy Energy Services are obligated to sell or contribute, on an ongoing basis and without recourse, their accounts receivable to TXU Energy's 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 acquired from TXU Energy and Dynegy Energy Services 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 consolidated statements of 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, 2019, outstanding borrowings under the receivables facility totaled $450 million and were supported by $629 million of RecCo gross receivables. As of December 31, 2018, outstanding borrowings under the receivables facility totaled $339 million.

11. LONG-TERM DEBT

Amounts in the table below represent the categories of long-term debt obligations incurred by the Company.

	December 31, 2019	December 31, 2018
Vistra Operations Credit Facilities	$ 2,700	$ 5,813
Vistra Operations Senior Secured Notes:		
3.550% Senior Secured Notes, due July 15, 2024	1,500	—
3.700% Senior Secured Notes, due January 30, 2027	800	—
4.300% Senior Secured Notes, due July 15, 2029	800	—
Total Vistra Operations Senior Secured Notes	3,100	—
Vistra Operations Senior Unsecured Notes:		
5.500% Senior Unsecured Notes, due September 1, 2026	1,000	1,000
5.625% Senior Unsecured Notes, due February 15, 2027	1,300	—
5.000% Senior Unsecured Notes, due July 31, 2027	1,300	—
Total Vistra Operations Senior Unsecured Notes	3,600	1,000
Vistra Energy Senior Unsecured Notes:		
7.375% Senior Unsecured Notes, due November 1, 2022	—	1,707
5.875% Senior Unsecured Notes, due June 1, 2023	500	500
7.625% Senior Unsecured Notes, due November 1, 2024	—	1,147
8.034% Senior Unsecured Notes, due February 2, 2024	—	25
8.000% Senior Unsecured Notes, due January 15, 2025 (a)	81	81
8.125% Senior Unsecured Notes, due January 30, 2026	166	166
Total Vistra Energy Senior Unsecured Notes	747	3,626
Other:		
7.000% Amortizing Notes, due July 1, 2019	—	24
Forward Capacity Agreements	161	236
Equipment Financing Agreements	99	120
Mandatorily redeemable subsidiary preferred stock (b)	—	70
8.82% Building Financing due semiannually through February 11, 2022 (c)	15	21
Other	12	—
Total other long-term debt	287	471
Unamortized debt premiums, discounts and issuance costs (d)	(55)	155
Total long-term debt including amounts due currently	10,379	11,065
Less amounts due currently	(277)	(191)
Total long-term debt less amounts due currently	$ 10,102	$ 10,874

(a) On January 15, 2020, Vistra Energy redeemed all outstanding 8.000% Senior Notes due 2025 at a redemption price equal to 104.0% of the aggregate principal amount thereof, plus accrued and unpaid interest to, but excluding the date of redemption.

(b) Shares of mandatorily redeemable preferred stock in PrefCo. This subsidiary preferred stock is accounted for as a debt instrument under relevant accounting guidance. On October 3, 2019, PrefCo redeemed all of the issued and outstanding preferred stock at a price per share equal to the preferred liquidation amount, plus accrued and unpaid dividends to and including the date of redemption.

(c) Obligation related to a corporate office space finance lease. This obligation will be funded by amounts held in an escrow account that is reflected in other noncurrent assets in our consolidated balance sheets.

(d) Includes impact of recording debt assumed in the Merger at fair value.

Vistra Operations Credit Facilities

At December 31, 2019, the Vistra Operations Credit Facilities consisted of up to $5.425 billion in senior secured, first-lien revolving credit commitments and outstanding term loans, which consisted of revolving credit commitments of up to $2.725 billion, including a $2.35 billion letter of credit sub-facility (Revolving Credit Facility) and term loans of $2.7 billion (Term Loan B-3 Facility). These amounts reflect the following transactions and amendments completed in 2018 and 2019:

- In November 2019, Vistra Operations used the net proceeds from the November 2019 Senior Secured Notes Offering described below and $799 million of incremental borrowings under the Term Loan B-3 Facility to repay the entire amount outstanding of $1.897 billion of term loans under the B-1 Facility (Term Loan B-1 Facility). Fees and expenses related to the transactions totaled $2 million in the year ended December 31, 2019, which were recorded as interest expense and other charges on the consolidated statements of operations.

- In October 2019, Vistra Operations borrowed $550 million under the Revolving Credit Facility. The proceeds of the borrowings were used for general corporate purposes, including the funding of a $425 million dividend to Vistra Energy to pay the principal, premium and interest due in connection with the redemption by Vistra Energy of the entire $387 million aggregate principal amount outstanding of 7.625% senior notes described below. In November 2019, Vistra Operations repaid $200 million under the Revolving Credit Facility.

- In June 2019, Vistra Operations used the net proceeds from the June 2019 Senior Secured Notes Offering described below to repay $889 million of loans under the Term Loan B-1 Facility, the entire amount outstanding of $977 million of term loans under the B-2 Facility (Term Loan B-2 Facility, and together with the Term Loan B-1 Facility and the Term Loan B-3 Facility, the Term Loan B Facility) and $134 million under the Term Loan B-3 Facility. We recorded an extinguishment loss of $4 million on the transactions in the year ended December 31, 2019.

- In March 2019 and May 2019, the Vistra Operations Credit Facilities were amended whereby we obtained $225 million of incremental Revolving Credit Facility commitments. The letter of credit sub-facility was also increased by $50 million. Fees and expenses related to the amendments to the Vistra Operations Credit Facilities totaled $2 million in the year ended December 31, 2019, which were capitalized as a noncurrent asset.

- In June 2018, the Vistra Operations Credit Facilities were amended 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 consolidated statements of operations, $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, 2019 are presented below.

		December 31, 2019		
Vistra Operations Credit Facilities	**Maturity Date**	**Facility Limit**	**Cash Borrowings**	**Available Capacity**
Revolving Credit Facility (a)	June 14, 2023	$ 2,725	$ 350	$ 1,426
Term Loan B-3 Facility (b)	December 31, 2025	2,700	2,700	—
Total Vistra Operations Credit Facilities		$ 5,425	$ 3,050	$ 1,426

(a) Facility to be used for general corporate purposes. Facility includes a $2.35 billion letter of credit sub-facility, of which $949 million of letters of credit were outstanding at December 31, 2019 and which reduce our available capacity. Cash borrowings under the Revolving Credit Facility are reported in short-term borrowings in our consolidated balance sheets.

(b) Beginning in 2020, cash borrowings under the Term Loan B-3 Facility are subject to a required scheduled quarterly payment in annual amount equal to 1.00% of the original principal amount with the balance paid at maturity. Amounts paid cannot be reborrowed.

In February 2018, June 2018 and November 2019, certain pricing terms for the Vistra Operations Credit Facilities were amended. We accounted for these transactions as modifications of debt. At December 31, 2019, 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 $350 million outstanding borrowings. Letters of credit issued under the Revolving Credit Facility bear interest of 1.75%. Amounts borrowed under the Term Loan B-3 Facilities bear interest based on applicable LIBOR rates plus fixed spreads of 1.75%. At December 31, 2019, the weighted average interest rates before taking into consideration interest rate swaps on outstanding borrowings was 3.54% under the Term Loan B-3 Facilities. 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, 2019, 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 — Vistra Energy employs interest rate swaps to hedge our exposure to variable rate debt. As of December 31, 2019, Vistra Energy has entered into the following series of interest rate swap transactions.

	Notional Amount	Expiration Date	Rate Range
Swapped to fixed	$3,000	July 2023	3.67 % - 3.91%
Swapped to variable	$700	July 2023	3.20 % - 3.23%
Swapped to fixed (a)	$720	February 2024	3.71 % - 3.72%
Swapped to variable	$720	February 2024	3.20 % - 3.20%
Swapped to fixed (b)	$3,000	July 2026	4.72 % - 4.79%
Swapped to variable (b)	$700	July 2026	3.28 % - 3.33%

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(a) In June 2018, we completed the novation of $1.959 billion of Vistra Energy (legacy Dynegy) interest rate swaps to Vistra Operations, of which $398 million expired and $841 million were terminated in June 2019.
(b) These swaps are effective from July 2023 through July 2026.

During the three months ended December 31, 2019, Vistra Energy entered into $2.120 billion of new interest rate swaps, pursuant to which Vistra Energy will pay a variable rate and receive a fixed rate. The terms of these new swaps were matched against the terms of certain existing swaps, effectively offsetting the hedge of the existing swaps and fixing the out-of-the-money position of such swaps. These matched swaps will settle over time, in accordance with the original contractual terms. The remaining existing swaps continue to hedge our exposure on $2.3 billion of debt from now through July 2026.

Alternative Letter of Credit Facility

Two alternate letter of credit facilities (each, an Alternative LOC Facility, and collectively, the Alternate LOC Facilities) with an aggregate facility limit of $500 million became effective in the year ended December 31, 2019. At December 31, 2019, $500 million of letters of credit were outstanding under the Alternate LOC Facilities. Of the total facility limit, $250 million matures in December 2020 and $250 million matures in December 2021.

Vistra Operations Senior Secured Notes

In 2019, Vistra Operations issued and sold $3.1 billion aggregate principal amount of senior secured notes (Senior Secured Notes) in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act (Senior Secured Notes Offerings) consisting of the following:

Senior Secured Notes	Maturity Year	Interest Terms (Due Semiannually in Arrears)	June 2019 Senior Secured Notes Offering (a)		November 2019 Senior Secured Notes Offering (b)	
3.550% Senior Secured Notes	2024	January 15 and July 15	$	1,200	$	300
3.700% Senior Secured Notes	2027	January 30 and July 30		—		800
4.300% Senior Secured Notes	2029	January 15 and July 15		800		—
Total senior secured notes			$	2,000	$	1,100
Net proceeds			$	1,976	$	1,099
Debt issuance and other fees (c)			$	20	$	10

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(a) The June 2019 Senior Secured 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, together with cash on hand, were used to prepay certain amounts outstanding and accrued interest (together with fees and expenses) under the Vistra Operations Credit Facility's Term Loan B Facility.
(b) The November 2019 Senior Secured 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, together with borrowings under the Term Loan B-3 Facility and cash on hand, were used to repay the entire amount outstanding and accrued interest (together with fees and expenses) under the Term Loan B-1 Facility.
(c) Capitalized as a reduction in the carrying amount of the debt.

The Senior Secured Notes are and will be fully and unconditionally guaranteed by certain of Vistra Operations' current and future subsidiaries that also guarantee the Vistra Operations Credit Facilities. The Senior Secured Notes are secured by a first-priority security interest in the same collateral that is pledged for the benefit of the lenders under the Vistra Operations Credit Facilities, which consists of a substantial portion of the property, assets and rights owned by Vistra Operations and certain direct and indirect subsidiaries of Vistra Operations as subsidiary guarantors (collectively, the Guarantor Subsidiaries) as well as the stock of Vistra Operations held by Vistra Intermediate. The collateral securing the Senior Secured Notes will be released if Vistra Operations' senior, unsecured long-term debt securities obtain an investment grade rating from two out of the three rating agencies, subject to reversion if such rating agencies withdraw the investment grade rating of Vistra Operations' senior, unsecured long-term debt securities or downgrade such rating below investment grade.

Vistra Operations Senior Unsecured Notes

In 2018 and 2019, Vistra Operations issued and sold $3.6 billion aggregate principal amount of senior unsecured notes (Vistra Operations Senior Unsecured Notes) in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act (Senior Unsecured Notes Offerings) consisting of the following:

Senior Unsecured Notes	Maturity Year	Interest Terms (Due Semiannually in Arrears)	August 2018 Senior Unsecured Notes Offering (a)	February 2019 Senior Unsecured Notes Offering (b)	June 2019 Senior Unsecured Notes Offering (c)
5.500% Senior Unsecured Notes	2026	March 1 and September 1	$ 1,000	$ —	$ —
5.625% Senior Unsecured Notes	2027	February 15 and August 15	—	1,300	—
5.000% Senior Unsecured Notes	2027	January 31 and July 31	—	—	1,300
Total			$ 1,000	$ 1,300	$ 1,300
Net Proceeds			$ 990	$ 1,287	$ 1,287
Debt issuance and other fees (d)			$ 12	$ 16	$ 13

(a) The August 2018 Senior Unsecured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, the Guarantor Subsidiaries and Citigroup Global Markets Inc., as representative of the several initial purchasers. Net proceeds, together with cash on hand and cash received from the funding of the Receivables Facility (see Note 10), were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with the 2018 Tender Offers.

(b) The February 2019 Senior Unsecured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, the Guarantor Subsidiaries and J.P. Morgan Securities LLC., as representative of the several initial purchasers. Net proceeds, 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 February 2019 Tender Offer, (ii) the redemption of approximately $35 million aggregate principal amount of our 7.375% senior unsecured notes due 2022 (7.375% senior notes) and approximately $25 million aggregate principal amount of our outstanding 8.034% senior unsecured notes due 2024 (8.034% senior notes).

(c) The June 2019 Senior Unsecured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, the Guarantor Subsidiaries and Goldman Sachs & Co. LLC, as representative of the several initial purchasers. Net proceeds, 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 June 2019 Tender Offer and (ii) the redemption of approximately $306 million of our outstanding 7.375% senior notes and approximately $87 million of our 7.625% senior unsecured notes due 2024 (7.625% senior notes) in July 2019. We recorded an extinguishment gain of $2 million on the redemptions in the year ended December 31, 2019.

(d) Capitalized as a reduction in the carrying amount of the debt.

The indentures governing the Vistra Operations Senior Unsecured Notes (collectively, as each may be amended or supplemented from time to time, the Vistra Operations Senior Unsecured Indentures) provide for the full and unconditional guarantee by the Guarantor Subsidiaries of the punctual payment of the principal and interest on such notes. The Vistra Operations Senior Unsecured Indentures contain 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 Unsecured 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 Unsecured Notes could be repurchased. Through December 31, 2019, $119 million principal amount of Vistra Energy Senior Unsecured Notes had been repurchased. In July 2019, the Board authorized up to $1.0 billion to repay or repurchase any outstanding debt of the Company (or its subsidiaries), with its authority superseding the previously authorized bond repurchase program.

January 2020 Redemption — In January 2020, Vistra Energy redeemed the entire $81 million aggregate principal amount outstanding of 8.000% senior unsecured notes due 2025 (8.000% senior notes) at a redemption price equal to 104.0% of the aggregate principal amount thereof, plus accrued and unpaid interest to, but excluding, the date of redemption.

November 2019 Redemption — In November 2019, Vistra Energy redeemed the entire $387 million aggregate principal amount outstanding of 7.625% senior notes at a redemption price equal to 103.8% of the aggregate principal amount thereof, plus accrued and unpaid interest to, but excluding, the date of redemption. We recorded an extinguishment gain of $9 million on the transaction in the year ended December 31, 2019.

June 2019 Tender Offer — In June 2019, Vistra Energy used the net proceeds from the June 2019 Notes Offering to fund a cash tender offer (the June 2019 Tender Offer) to purchase for cash $845 million aggregate principal amount of certain notes assumed in the Merger, including $173 million of 7.375% senior notes and $672 million of 7.625% senior notes. We recorded an extinguishment gain of $7 million on the transactions in the year ended December 31, 2019. In July 2019, Vistra Energy accepted and settled an additional approximately $1 million aggregate principal amount of outstanding 7.625% senior notes that were tendered after the early tender date of the June 2019 Tender Offer.

February 2019 Tender Offer and Consent Solicitation — In February 2019, Vistra Energy used the net proceeds from the February 2019 Senior Unsecured Notes Offering to fund a cash tender offer (the February 2019 Tender Offer) to purchase for cash $1.193 billion aggregate principal amount of 7.375% senior notes assumed in the Merger.

In connection with the February 2019 Tender Offer, Vistra Energy also commenced solicitation of consents from holders of the 7.375% senior notes. Vistra Energy received the requisite consents from the holders of the 7.375% senior notes 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 August 2018 Senior Unsecured Notes Offering, proceeds from the Receivables Facility (see Note 10) and cash on hand to fund cash tender offers (the 2018 Tender Offers) to purchase for cash $1.542 billion aggregate principal amount of Vistra Energy Senior Unsecured 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;
- $163 million of 8.034% senior notes;
- $669 million of 8.000% senior notes, and
- $684 million of 8.125% senior unsecured notes due 2026 (8.125% senior notes).

In connection with the 2018 Tender Offers, Vistra Energy also commenced solicitations of consents from holders of the 7.375% senior notes, the 7.625% senior notes, the 8.034% senior notes, the 8.000% senior notes and the 8.125% senior notes 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. Vistra Energy received the requisite consents from the holders of the 8.034% senior notes, the 8.000% senior notes and the 8.125% senior notes (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 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 unsecured notes. In May 2018, $850 million of outstanding 6.75% senior unsecured notes due 2019 were redeemed at a redemption price of 101.7% of the aggregate principal amount, plus accrued and unpaid interest up to but not including the date of redemption. Fees and expenses related to the redemption totaled $14 million in the year ended December 31, 2018 and were recorded as interest expense and other charges on the consolidated statements of operations. 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 June 2019 Tender Offer, the February 2019 Tender Offer and the 2018 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 22). Except with respect to the Consent Senior Notes, the respective indentures of the senior notes of Vistra Energy (collectively, as each may be amended or supplemented from time to time, the Vistra Energy Senior Unsecured Indentures) 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 Vistra Energy Senior Unsecured Indentures 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.

Other Long-Term Debt

Amortizing Notes — On the Merger Date, Vistra Energy assumed the obligations of Dynegy's senior unsecured amortizing note (Amortizing Notes) that matured on July 1, 2019. The Amortizing Notes were issued in connection with the issuance of the tangible equity units (TEUs) by Dynegy (see Note 14). Each installment payment per Amortizing Note was paid in cash and constituted a partial repayment of principal and a payment of interest, computed at an annual rate of 7.00%. Interest was calculated on the basis of a 360-day year consisting of twelve 30-day months. Payments were 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 (Amortizing Notes Indenture). On the maturity date, the Company paid all amounts due under the Amortizing Notes Indenture and the Amortizing Notes Indenture ceased to be of further force and effect.

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 2019-2020 and 2020-2021 in the amounts of $51 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 $161 million with an implied interest rate of 3.01%.

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.

Mandatorily Redeemable Subsidiary Preferred Stock — In October 2019, PrefCo voluntarily redeemed the entire $70 million aggregate principal amount outstanding of its authorized preferred stock at a price per share equal to the preferred liquidation amount, plus accrued and unpaid dividends to and including the date of redemption.

Debt Assumed in Crius Transaction — On the Crius Acquisition Date, Vistra Energy assumed $140 million in long-term debt obligations in connection with the Crius Transaction consisting of the following:

- $44 million of 9.5% promissory notes due July 2025 (2025 promissory notes);
- $8 million of 2% Connecticut Department of Economic and Community Development (CT DECD) term loans due February 2027, and
- $88 million of borrowings and $9 million of issued letters of credit under the legacy Crius credit facility.

In July 2019, borrowings of $88 million under the legacy Crius credit facility were repaid using cash on hand. In November 2019, (i) borrowings of approximately $38 million under the 2025 promissory notes were repaid using cash on hand and (ii) borrowings of approximately $2 million were offset by legacy indemnification obligations of the holders of the 2025 promissory notes. In November 2019, borrowings of $8 million under the CT DECD term loans were repaid using cash on hand.

Debt Assumed in Ambit Transaction — All of the indebtedness outstanding at Ambit immediately prior to the closing of the Ambit Transaction was repaid at closing out of the purchase price.

At December 31, 2019, approximately $8 million of letters of credit were outstanding under legacy Ambit agreements, all of which are collateralized with cash and recorded as restricted cash in the consolidated balance sheets.

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.

Maturities

Long-term debt maturities at December 31, 2019 are as follows:

	December 31, 2019
2020	$ 273
2021	94
2022	42
2023	538
2024	1,538
Thereafter	7,949
Unamortized premiums, discounts and debt issuance costs	(55)
Total long-term debt, including amounts due currently	$ 10,379

12. LEASES

Vistra has both finance and operating leases for real estate, rail cars and equipment. Our leases have remaining lease terms for 1 to 38 years. Our leases include options to renew up to 15 years. Certain leases also contain options to terminate the lease.

Lease Cost

The following table presents costs related to lease activities:

	Year Ended December 31, 2019
Operating lease cost	$ 14
Finance lease:	
Finance lease right-of-use asset amortization	4
Interest on lease liabilities	4
Total finance lease cost	8
Variable lease cost (a)	26
Short-term lease cost	19
Sublease income (b)	(8)
Net lease cost	$ 59

(a) Represents coal stockpile management services, common area maintenance services and rail car payments based on the number of rail cars used.
(b) Represents sublease income related to real estate leases.

Balance Sheet Information

The following table presents lease related balance sheet information:

	December 31, 2019
Lease assets:	
Operating lease right-of-use assets	$ 44
Finance lease right-of-use assets (net of accumulated depreciation)	59
Total lease right-of-use assets	103
Current lease liabilities:	
Operating lease liabilities	14
Finance lease liabilities	8
Total current lease liabilities	22
Noncurrent lease liabilities:	
Operating lease liabilities	41
Finance lease liabilities	78
Total noncurrent lease liabilities	119
Total lease liabilities	$ 141

Cash Flow and Other Information

The following table presents lease related cash flow and other information:

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 17
Operating cash flows from finance leases	4
Finance cash flows from finance leases	4
Non-cash disclosure upon commencement of new lease:	
Right-of-use assets obtained in exchange for new operating lease liabilities	95
Right-of-use assets obtained in exchange for new finance lease liabilities	13
Non-cash disclosure upon modification of existing lease:	
Modification of operating lease right-of-use assets	(41)
Modification of finance lease right-of-use assets	50

Weighted Average Remaining Lease Term

The following table presents weighted average remaining lease term information:

	December 31, 2019
Weighted average remaining lease term:	
Operating lease	7.5 years
Finance lease	16.2 years
Weighted average discount rate:	
Operating lease	5.34%
Finance lease	5.84%

Maturity of Lease Liabilities

The following table presents maturity of lease liabilities:

	Operating Lease	Finance Lease	Total Lease
2020	$ 17	$ 12	$ 29
2021	11	11	22
2022	9	11	20
2023	10	10	20
2024	6	10	16
Thereafter	13	69	82
Total lease payments	66	123	189
Less: Interest	(11)	(37)	(48)
Present value of lease liabilities	$ 55	$ 86	$ 141

As of December 31, 2019, we have approximately $24 million of operating leases that have not yet commenced.

13. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

At December 31, 2019, 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
2020	$ 167	$ 576	$ 109	$ 90	$ 174
2021	153	61	83	74	30
2022	171	47	55	54	16
2023	152	33	46	57	16
2024	161	34	32	39	17
Thereafter	1,975	112	138	140	51
Total	$ 2,779	$ 863	$ 463	$ 454	$ 304

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 $1.092 billion, $955 million, and $416 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Rent reported as operating costs, fuel costs and SG&A expenses totaled $89 million, $74 million, and $69 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Guarantees

We have entered into contracts, including the assumed Dynegy senior unsecured notes described above, that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2019, 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 in the near term.

Letters of Credit

At December 31, 2019, we had outstanding letters of credit totaling $1.457 billion as follows:

- $1.150 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;
- $155 million to support battery and solar development projects;
- $47 million to support executory contracts and insurance agreements;
- $38 million to support our REP financial requirements with the PUCT, and
- $67 million for other credit support requirements.

Surety Bonds

At December 31, 2019, we had outstanding surety bonds totaling $62 million to support performance under various contracts and legal obligations in the normal course of business.

Litigation and Regulatory Proceedings

Our material legal proceedings and regulatory proceedings affecting our business are described below. We believe that we have valid defenses to the legal proceedings described below and intend to defend them vigorously. We also intend to participate in the regulatory processes described below. We record reserves for estimated losses related to these matters when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. As applicable, we have established an adequate reserve for the matters discussed below. In addition, legal costs are expensed as incurred. Management has assessed each of the following legal matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, we are unable to predict the outcome of these matters or reasonably estimate the scope or amount of any associated costs and potential liabilities, but they could have a material impact on our results of operations, liquidity, or financial condition. As additional information becomes available, we adjust our assessment and estimates of such contingencies accordingly. Because litigation and rulemaking proceedings are subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of these matters could be at amounts that are different from our currently recorded reserves and that such differences could be material.

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 during the relevant time period and seek damages under the respective state antitrust statutes. We remain as defendants in two consolidated putative class actions (Wisconsin) and one individual action (Kansas) both pending in federal court in those states.

Advatech Dispute — In October 2018, Illinois Power Generating Company (Genco) defended an arbitration filed by Advatech LLC (Advatech) alleging $81 million in termination charges under the Second Amended and Restated Newton Flue Gas Desulfurization System Engineering, Procurement, Construction and Commissioning Services Contract dated as of December 15, 2014. An arbitration panel issued a final award in June 2019. In June 2019, Genco moved to vacate the award in the U.S. District Court for the Southern District of Illinois, and Advatech moved to confirm the award in the U.S. District Court for the Northern District of Illinois, which was stayed pending a decision by the Southern District of Illinois on the issue of venue. In December 2019, the parties entered into a confidential settlement to resolve the matter for less than the amount of the liability that the Company recorded as part of our purchase price allocation of the Merger. In connection with the settlement, both parties dismissed their lawsuits related to the award with prejudice and Advatech dismissed its related mechanic lien action and released its mechanics lien on the Newton plant. This matter is fully resolved.

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 and an arbitration hearing is currently scheduled for November 2020.

ME2C Patent Dispute – In July 2019, Midwest Energy Emissions Corporation and MES Inc. (collectively, the plaintiffs) filed a patent infringement complaint in federal court in Delaware against numerous parties, including Vistra Energy and some of its subsidiaries (collectively, the Vistra defendants). The complaint alleges that the Vistra defendants infringed two patents owned by the plaintiffs by using specific processes for mercury control at certain coal-fueled plants. The complaint seeks injunctive relief and unspecified damages.

Greenhouse Gas Emissions

In August 2015, the EPA finalized rules to address greenhouse gas (GHG) emissions from 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 filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court). In July 2019, petitioners filed a joint motion to dismiss in light of the EPA's new rule that replaces the Clean Power Plan, the Affordable Clean Energy rule, discussed below. In September 2019, the D.C. Circuit Court granted petitioners' motion to dismiss and dismissed all of the petitions challenging the Clean Power Plan as moot.

In July 2019, the EPA finalized a rule to repeal the Clean Power Plan, with new regulations addressing GHG emissions from existing coal-fueled electric generation units, referred to as the Affordable Clean Energy (ACE) rule. The ACE rule develops emission guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. States must submit their plans for regulating GHG emissions from existing facilities by July 2022. States where we operate coal plants (Texas, Illinois and Ohio) have begun the development of their state plans to comply with the rule. Environmental groups and certain states filed petitions for review of the ACE rule and the repeal of the Clean Power Plan in the D.C. Circuit Court. Additionally, in December 2018, the EPA issued proposed revisions to the emission standards for new, modified and reconstructed units. Vistra Energy submitted comments on that proposed rulemaking.

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, various parties (including Luminant and 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 pending final review of the petitions for review. In March 2017, the Fifth Circuit Court granted a motion by the EPA to remand the rule back to the EPA for reconsideration. The stay of the rule (and the emission control requirements) remains in effect. The retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation since these plants constitute a large portion of the plants that the rule seeks to regulate. Further, we believe that these retirements and the BART rule (discussed below) obviates the need for any additional limits on our remaining Texas plants to address the requirements in the regional haze rule.

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. 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. Various parties 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 abated its proceedings until the EPA concludes the reconsideration process. In August 2018, the EPA issued a proposal to affirm the prior BART final rule and seeking comments on that proposal, which were due in October 2018. In November 2019, the EPA proposed additional revisions to the BART final rule, and we submitted comments on that proposal in January 2020.

Affirmative Defenses During Malfunctions

In May 2015, the EPA finalized a rule requiring 36 states, including Texas, Illinois and Ohio, to remove or replace either EPA-approved exemptions or affirmative defense provisions for excess emissions during upset events and unplanned maintenance and startup and shutdown events, referred to as the SIP Call. Various parties (including Luminant, the State of Texas and the State of Ohio) filed petitions for review of the EPA's final rule, and all of those petitions were consolidated in the D.C. Circuit Court. In April 2017, the D.C. Circuit Court ordered the case to be held in abeyance. In April 2019, the EPA Region 6 proposed a rule to withdraw the SIP Call with respect to the Texas affirmative defense provisions. We submitted comments on that proposed rulemaking in June 2019. In January 2020, the EPA took final action to withdraw the Texas SIP Call.

Illinois Multi-Pollutant Standards (MPS)

In August 2019, changes proposed by the Illinois Pollution Control Board to the Illinois multi-pollutant standard rule (MPS rule), which places NOx, SO_2 and mercury emissions limits on our coal plants located in MISO went into effect. Under the revised MPS rule, our allowable SO_2 and NOx emissions from the MISO fleet are 48% and 42% lower, respectively, than prior to the rule changes. The revised MPS rule requires the continuous operation of existing selective catalytic reduction (SCR) control systems during the ozone season, requires SCR-controlled units to meet an ozone season NOx emission rate limit, and set an additional, site-specific annual SO_2 limit for our Joppa Power Station. Additionally, in 2019, the Company retired its Havana, Hennepin, Coffeen and Duck Creek plants in order to comply with the MPS rule's requirement to retire at least 2,000 MW of the company's generation in MISO. See Note 4 for information regarding the retirement of the four plants.

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 August 2019, the EPA issued a proposed Error Correction Rule for all three areas, which, if finalized, would revise its previous nonattainment designations and each area at issue would be designated unclassifiable. In September 2019, we submitted comments in support of the proposed Error Correction 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, such as flue gas desulfurization (FGD), fly ash, bottom ash and flue gas mercury control wastewaters. 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 rule and administratively stayed the rule's compliance date deadlines. In August 2017, the EPA announced that its reconsideration of the ELG rule would be limited to a review of the effluent limitations applicable to FGD and bottom ash wastewaters and the agency subsequently postponed the earliest compliance dates in the ELG rule for the application of effluent limitations for FGD and bottom ash wastewaters from November 1, 2018 to November 1, 2020. Based on these administrative developments, the Fifth Circuit Court agreed to sever and hold in abeyance challenges to effluent limitations. The remainder of the case proceeded, and in April 2019 the Fifth Circuit Court vacated and remanded portions of the EPA's ELG rule pertaining to effluent limitations for legacy wastewater and leachate. In November 2019, the EPA issued a proposal that would extend the compliance deadline for FGD wastewater to no later than December 31, 2025 and maintains the December 31, 2023 compliance date for bottom ash transport water. The proposal also creates new sub-categories of facilities with more flexible FGD compliance options, including a retirement exemption to 2028 and a low utilization boiler exemption. The proposed rule also modified some of the FGD final effluent limitations. We filed comments on the proposal in January 2020.

Given the EPA's decision to reconsider the FGD and bottom ash wastewater provisions of the ELG rule, the rule postponing the ELG rule's earliest compliance dates for those provisions, the uncertainty stemming from the vacatur of the effluent limitations for legacy wastewater and leachate, 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.

CAA Matters

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. In January 2020, the U.S. Department of Justice filed a complaint and proposed consent decree agreed to by Dynegy Zimmer, LLC in the U.S. District Court for the Southern District of Ohio that would resolve claims alleged in the 2008, 2010 and 2014 NOVs. The court has not yet entered the consent decree as effective. We believe that if the consent decree is entered by the court as proposed, it will not have a material impact on our results of operations, liquidity or financial condition.

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 against one of our subsidiaries that owns the Edwards Power Plant 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. In September 2019, the parties to the lawsuit announced a proposed settlement which was approved by the court in a consent decree in November 2019. The consent decree requires the retirement of the Edwards plant by the end of 2022 and funding for certain projects that benefit Peoria-area communities. See Note 4 for information regarding the retirement of the Edwards plant.

Coal Combustion Residuals (CCR)/Groundwater

In July 2018, the EPA published a final rule, which became effective in August 2018, that amends certain provisions of the CCR rule that the agency issued in 2015. Among other changes, the 2018 revisions extend closure deadlines to October 31, 2020, related to the aquifer location restriction and groundwater monitoring requirements. Also, in August 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule, including an applicability exemption for legacy impoundments. 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 March 2019, the D.C. Circuit Court granted the EPA's request for remand without vacatur. In December 2019, the EPA issued a proposed rule that would revise the closure deadlines for unlined CCR impoundments from October 31, 2020 to August 31, 2020 and establish new procedures for seeking extensions of that revised closure deadline. One of the new proposed extension procedures would require the generation plant electing this option to notify the EPA by May 2020 that it will retire by either 2023 or 2028 depending on the size of the impoundment at issue. If the rule is finalized as proposed, we may decide to avail ourselves of this compliance mechanism for some of our facilities. We filed comments on the proposal in January 2020.

MISO — 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. These violation notices remain unresolved; however, 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 aforementioned D.C. Circuit Court decision in August 2018, 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, and we submitted revised plans 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. In May 2018, Prairie Rivers Network filed a citizen suit in federal court in Illinois against our subsidiary Dynegy Midwest Generation, LLC (DMG), 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 Seventh Circuit. That appeal is now stayed. In April 2019, PRN also filed a complaint against DMG before the IPCB, alleging that groundwater flows allegedly associated with the ash impoundments at the Vermilion site have resulted in exceedances both of surface water standards and Illinois groundwater standards dating back to 1992. This matter is in the very early stages.

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 and that notice has since been referred to the Illinois Attorney General.

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.

In July 2019, coal ash disposal and storage legislation in Illinois was enacted. The legislation addresses state requirements for the proper closure of coal ash ponds in the state of Illinois. The law tasks the IEPA and the IPCB to set up a series of guidelines, rules and permit requirements for closure of ash ponds. We anticipate IEPA's proposed rule will be issued in March 2020 and expect the rulemaking process should be completed by early 2021. Under the new law, coal ash impoundment owners would be required to submit a closure alternative analysis to the IEPA for the selection of the best method for coal ash remediation at a particular site. The law does not mandate closure by removal at any site.

For all of the above matters, if certain corrective action measures, including groundwater treatment or removal of ash, 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, the D.C. Circuit Court's vacatur and remand of certain provisions of the EPA's 2015 CCR rule and the Illinois coal ash rulemaking, we cannot reasonably estimate the costs, or range of costs, of groundwater remediation, if any, that ultimately may be required. The currently anticipated CCR surface impoundment and landfill closure costs, as contained in our AROs, reflect the costs of closure methods that our operations and environmental services teams believe are appropriate and protective of the environment for each location.

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. (Complainants), challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds, and requested changes to the MISO planning resource auction structure going forward. Complainants also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the PRA. The Independent Market Monitor for MISO (MISO IMM), which was responsible for monitoring the 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 remedies sought by the Complainants. We filed our answer to these complaints explaining that we complied fully with the terms of the MISO tariff in connection with the PRA and disputing the allegations. The Illinois Industrial Energy Consumers filed a related complaint at FERC against MISO in June 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint with respect to Dynegy's conduct alleged in the complaint.

In October 2015, FERC issued an order of nonpublic, formal investigation (the investigation) into whether market manipulation or other potential violations of FERC orders, rules and regulations occurred before or during the PRA.

In December 2015, FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions effective as of the 2016-2017 planning resource auction. The order did not address the arguments of the Complainants regarding the PRA and stated that those issues remained under consideration and would be addressed in a future order.

In July 2019, FERC issued an order denying the remaining issues raised by the complaints and noted that the investigation into Dynegy was closed. FERC found that Dynegy's conduct did not constitute market manipulation and the results of the PRA were just and reasonable because the PRA was conducted in accordance with MISO's tariff. With the issuance of the order, this matter has been resolved in Dynegy's favor. The order remains subject to rehearing at FERC and appeal.

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 June 2020 and November 2023, but remain effective 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 $13.5 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 $13.5 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, 2019, 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.

14. EQUITY

Equity Issuances and Repurchases

Changes in the number of shares of common stock issued and outstanding for the years ended December 31, 2019, 2018 and 2017 are reflected in the table below.

	Shares Issued	Treasury Shares	Shares Outstanding
Balance at December 31, 2016	427,580,232	—	427,580,232
Shares issued (a)	818,570	—	818,570
Balance at December 31, 2017	428,398,802	—	428,398,802
Shares issued (a) (b)	97,639,105	—	97,639,105
Shares retired	(6,815)	—	(6,815)
Shares repurchased	—	(32,815,783)	(32,815,783)
Balance at December 31, 2018	526,031,092	(32,815,783)	493,215,309
Shares issued (a) (c)	2,716,349	18,773,958	21,490,307
Shares retired	(6,106)	—	(6,106)
Shares repurchased	—	(27,001,399)	(27,001,399)
Balance at December 31, 2019	528,741,335	(41,043,224)	487,698,111

(a) Shares issued includes share awards granted to nonemployee directors.
(b) The year ended December 31, 2018 includes 94,409,573 shares issued in connection with the Merger (see Note 2).
(c) The year ended December 31, 2019 includes 18,773,958 treasury shares issued in connection with the settlement of all outstanding TEUs as discussed 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 may be purchased. Repurchases under this program were completed in October 2018. 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, resulting in an aggregate $1.750 billion share repurchase program. At December 31, 2019, $332 million was available for additional repurchases under the Program. Shares of common stock repurchased under the program for the years ended December 31, 2019 and 2018 are reflected in the table below.

	$500 Million Board Authorization			$1.250 Billion Board Authorization		
	Total Number of Shares Repurchased	Average Price Paid Share	Amount Paid for Shares Repurchased	Total Number of Shares Repurchased	Average Price Paid Share	Amount Paid for Shares Repurchased
Year Ended December 31, 2018	21,421,925	$ 23.36	$ 500	12,073,091	$ 22.99	$ 278
Year Ended December 31, 2019	—	—	—	26,322,166	24.34	640
Totals	21,421,925	$ 23.36	$ 500	38,395,257	$ 23.92	$ 918

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 Exchange Act, or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the Program or otherwise will be determined at our discretion and will depend on a number of factors, including our capital allocation priorities, 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

In November 2018, Vistra Energy announced the Board had adopted a dividend program which we initiated 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, Vistra Energy's results of operations, financial condition and liquidity, Delaware law and any contractual limitations.

In February 2019, May 2019, July 2019 and October 2019, the Board declared quarterly dividends of $0.125 per share that were paid in March 2019, June 2019, September 2019 and December 2019, respectively.

In February 2020, the Board declared a quarterly dividend of $0.135 per share that will be paid in March 2020. Vistra Energy did not declare or pay any dividends during the year ended December 31, 2018.

Dividend Restrictions

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, 2019, Vistra Operations can distribute approximately $6.0 billion to Parent under the Credit Facilities Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Parent of approximately $3.9 billion, $4.7 billion and $1.1 billion during the years ended December 31, 2019, 2018 and 2017, respectively. Additionally, Vistra Operations may make distributions to Parent in amounts sufficient for Parent to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Parent's ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2019, the maximum amount of restricted net assets of Vistra Operations that may not be distributed to Parent totaled approximately $2.1 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, 2019, 2018 and 2017, we recorded changes in the funded status of our pension and other postretirement employee benefit liability totaling $11 million, $9 million and $(23) million, respectively. During the years ended December 31, 2019 and 2018, $(3) million and $(3) million was reclassified from accumulated other comprehensive income and reported in other deductions. During the year ended December 31, 2017, 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, 2019, nine million warrants expiring in 2024 with an exercise price of $35.00 (subject to adjustment from time-to-time) 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 sheets.

Tangible Equity Units (TEUs)

At the Merger Date, the Company assumed the obligations of Dynegy's 4,600,000 7.00% TEUs, each with a stated amount of $100.00 and each comprised of (i) a prepaid stock purchase contract that delivered to the holder on July 1, 2019, 4.0813 shares of Vistra Energy common stock per contract with cash paid in lieu of any fractional shares at a rate of $22.5954 per share and (ii) a senior amortizing note with an outstanding principal amount of $38 million at the Merger Date that paid an equal quarterly cash installment of $1.75 per amortizing note (see Note 11). In the aggregate, the annual quarterly cash installments were equivalent to a 7.00% cash payment per year with respect to each $100.00 stated amount of TEUs. The amortizing notes were accounted for as debt while the stock purchase contract was included in equity based on the fair value of the contract at the Merger Date. The entire class of TEUs were suspended from trading on the New York Stock Exchange on July 1, 2019 and removed from listing and registration on July 12, 2019. On July 1, 2019, approximately 18.8 million treasury shares of Vistra Energy common stock were issued in connection with the settlement of all outstanding TEUs.

15. 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 16 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, 2019				
	Level 1	Level 2	Level 3 (a)	Reclassification (b)	Total
Assets:					
Commodity contracts	$ 1,047	$ 172	$ 239	$ 11	$ 1,469
Interest rate swaps	—	—	—	—	—
Nuclear decommissioning trust – equity securities (c)	564	—	—	—	564
Nuclear decommissioning trust – debt securities (c)	—	521	—	—	521
Sub-total	$ 1,611	$ 693	$ 239	$ 11	2,554
Assets measured at net asset value (d):					
Nuclear decommissioning trust – equity securities (c)					366
Total assets					$ 2,920
Liabilities:					
Commodity contracts	$ 985	$ 439	$ 313	$ 11	$ 1,748
Interest rate swaps	—	177	—	—	177
Total liabilities	$ 985	$ 616	$ 313	$ 11	$ 1,925

	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

(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 21.
(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, 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 16 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, 2019 and 2018:

December 31, 2019

	Fair Value							
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**		
Electricity purchases and sales	$ 64	$ (53)	$ 11	Valuation Model	Hourly price curve shape (c)	$ —	to	$ 115 MWh
					Illiquid delivery periods for ERCOT hub power prices and heat rates (d)	$ 20	to	$ 120 MWh
Options	38	(188)	(150)	Option Pricing Model	Gas to power correlation (e)	10 %	to	100 %
					Power and gas volatility (e)	5 %	to	440 %
Financial transmission rights	120	(26)	94	Market Approach (f)	Illiquid price differences between settlement points (g)	$ (10)	to	$ 40 MWh
Other (h)	17	(46)	(29)					
Total	$ 239	$ (313)	$ (74)					

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)	$ —	to	$ 110 MWh
					Illiquid delivery periods for ERCOT hub power prices and heat rates (d)	$ 20	to	$ 120 MWh
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)					

(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. Options consist of physical electricity options, spread options, swaptions and natural gas 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 prices and ERCOT heat rate variability.
(e) Primarily based on the 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 and emissions.

There were no transfers between Level 1 and Level 2 of the fair value hierarchy for the years ended December 31, 2019, 2018 and 2017. See the table below for discussion of transfers between Level 2 and Level 3 for the years ended December 31, 2019, 2018 and 2017.

The following table presents the changes in fair value of the Level 3 assets and liabilities for the years ended December 31, 2019, 2018 and 2017.

	Year Ended December 31,		
	2019	2018	2017
Net asset (liability) balance at beginning of period	$ (135)	$ (53)	$ 83
Total unrealized valuation gains (losses)	8	(363)	(136)
Purchases, issuances and settlements (a):			
Purchases	176	146	69
Issuances	(81)	(41)	(22)
Settlements	(64)	76	(106)
Transfers into Level 3 (b)	10	4	4
Transfers out of Level 3 (b)	12	133	71
Net liabilities assumed in connection with the Merger	—	(37)	—
Earn-out provision (c)	—	—	(16)
Net change (d)	61	(82)	(136)
Net liability balance at end of period	$ (74)	$ (135)	$ (53)
Unrealized valuation losses relating to instruments held at end of period	$ (61)	$ (174)	$ (98)

(a) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received and purchases of Financial Transmission Rights.
(b) 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, 2019, 2018 and 2017, transfers out of Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become observable.
(c) Represents initial fair value of the earn-out provision agreed to as part of the Odessa Acquisition.
(d) Activity excludes change in fair value in the month positions settle. Substantially all changes in values of commodity contracts (excluding the net liabilities assumed in connection with the Merger) are reported as operating revenues in our consolidated statements of operations.

16. 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 15 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 and to hedge future purchased power costs for our retail operations. We also utilize short-term electricity, natural gas, coal 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 consolidated statements of operations in operating revenues and fuel, purchased power costs and delivery fees.

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 as well as realized gains and losses upon settlement of the swaps are reported in our consolidated statements of operations 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, 2019 and 2018. 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, 2019				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 1,323	$ —	$ 10	$ —	$ 1,333
Noncurrent assets	136	—	—	—	136
Current liabilities	(1)	—	(1,510)	(18)	(1,529)
Noncurrent liabilities	—	—	(237)	(159)	(396)
Net assets (liabilities)	$ 1,458	$ —	$ (1,737)	$ (177)	$ (456)

	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)

At December 31, 2019 and 2018, 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.

	Year Ended December 31,		
Derivative (consolidated statements of operations presentation)	2019	2018	2017
Commodity contracts (Operating revenues)	$ 339	$ (855)	$ 56
Commodity contracts (Fuel, purchased power costs and delivery fees)	(1)	18	6
Interest rate swaps (Interest expense and related charges)	(217)	(11)	2
Net gain (loss)	$ 121	$ (848)	$ 64

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 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, 2019				December 31, 2018			
	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	$ 1,458	$ (1,113)	$ —	$ 345	$ 761	$ (593)	$ (1)	$ 167
Interest rate swaps	—	—	—	—	77	(26)	—	51
Total derivative assets	1,458	(1,113)	—	345	838	(619)	(1)	218
Derivative liabilities:								
Commodity contracts	(1,737)	1,113	40	(584)	(1,611)	593	109	(909)
Interest rate swaps	(177)	—	—	(177)	(34)	26	—	(8)
Total derivative liabilities	(1,914)	1,113	40	(761)	(1,645)	619	109	(917)
Net amounts	$ (456)	$ —	$ 40	$ (416)	$ (807)	$ —	$ 108	$ (699)

(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, 2019 and 2018:

Derivative type	December 31, 2019	December 31, 2018	Unit of Measure
	Notional Volume		
Natural gas (a)	6,160	7,011	Million MMBtu
Electricity	428,367	317,572	GWh
Financial transmission rights (b)	199,648	172,611	GWh
Coal	22	45	Million U.S. tons
Fuel oil	33	60	Million gallons
Uranium	—	50	Thousand pounds
Emissions	20	10	Million tons
Renewable energy certificates	11	—	Million certificates
Interest rate swaps – floating/fixed (c)	$ 6,720	$ 7,717	Million U.S. dollars
Interest rate swaps - fixed/floating (c)	$ 2,120	$ —	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. See Note 11 for termination of interest rate swaps.

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, 2019	December 31, 2018
Fair value of derivative contract liabilities (a)	$ (692)	$ (856)
Offsetting fair value under netting arrangements (b)	167	218
Cash collateral and letters of credit	67	190
Liquidity exposure	$ (458)	$ (448)

(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, 2019, total credit risk exposure to all counterparties related to derivative contracts totaled $1.621 billion (including associated accounts receivable). The net exposure to those counterparties totaled $403 million at December 31, 2019 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure to a single counterparty totaling $106 million. At December 31, 2019, the credit risk exposure to the banking and financial sector represented 74% of the total credit risk exposure and 40% 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.

17. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

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 participants who were 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

	Year Ended December 31,		
	2019	2018	2017
Pension costs	$ 9	$ 14	$ 6
OPEB costs	11	9	6
Total benefit costs recognized as expense	$ 20	$ 23	$ 12

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, 2019, 2018 and 2017 measurement dates:

	Year Ended December 31,		
	2019	2018	2017
Assumptions Used to Determine Net Periodic Pension Cost:			
Discount rate (Vistra Energy Plan)	4.37 %	3.74 %	4.31 %
Discount rate (Dynegy Plan & EEI Plan)	4.37 %	4.05 %	— %
Expected return on plan assets (Vistra Energy Plan)	4.80 %	4.56 %	4.86 %
Expected return on plan assets (Dynegy Plan)	5.31 %	5.94 %	— %
Expected return on plan assets (EEI Plan)	5.56 %	4.74 %	— %
Expected rate of compensation increase (Vistra Energy Plan)	3.35 %	3.62 %	3.50 %
Expected rate of compensation increase (Dynegy Plan & EEI Plan)	3.35 %	3.50 %	— %
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 Plan)	3.50 %	4.25 %	— %
Components of Net Pension Cost:			
Service cost	$ 7	$ 15	$ 5
Interest cost	25	21	6
Expected return on assets	(26)	(23)	(5)
Immediate pension cost	3	1	—
Net periodic pension cost	$ 9	$ 14	$ 6
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:			
Net (gain) loss	$ 11	$ 14	$ 3
Total recognized in net periodic benefit cost and other comprehensive income	$ 20	$ 28	$ 9
Assumptions Used to Determine Benefit Obligations:			
Discount rate (Vistra Plan)	3.24 %	4.37 %	3.74 %
Expected rate of compensation increase (Vistra Plan)	3.29 %	3.35 %	3.62 %
Discount rate (Dynegy Plan)	3.24 %	4.37 %	— %
Expected rate of compensation increase (Dynegy Plan)	3.29 %	3.35 %	— %
Interest crediting rate for cash balance plans (Vistra Energy Plan)	3.50 %	3.50 %	3.50 %
Interest crediting rate for cash balance plans (Dynegy Plan & EEI)	3.50 %	3.50 %	— %

For the year ended December 31, 2019, the net actuarial loss of $16 million was driven by losses attributable to decreasing discount rates due to changes in the corporate bond markets, actuarial assumption updates to reflect current market conditions, annuity purchases, plan amendments and plan experience different than expected, partially offset by gains attributable to actual asset performance exceeding expectations and life expectancy updates.

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.

	Year Ended December 31,	
	2019	2018
Change in Pension Obligation:		
Projected benefit obligation at beginning of period	$ 615	$ 163
Acquisitions	—	502
Service cost	7	15
Interest cost	25	21
Settlement	—	(28)
Curtailment	(2)	—
Annuity purchase	(18)	—
Actuarial (gain) loss	93	(34)
Benefits paid	(46)	(24)
Projected benefit obligation at end of year	$ 674	$ 615
Accumulated benefit obligation at end of year	$ 669	$ 611
Change in Plan Assets:		
Fair value of assets at beginning of period	$ 490	$ 128
Acquisitions	—	428
Employer contributions	—	12
Settlement	—	(28)
Annuity purchase	(18)	—
Actual gain (loss) on assets	102	(26)
Benefits paid	(46)	(24)
Fair value of assets at end of year	$ 528	$ 490
Funded Status:		
Projected pension benefit obligation	$ (674)	$ (615)
Fair value of assets	528	490
Funded status at end of year	$ (146)	$ (125)
Amounts Recognized in the Balance Sheet Consist of:		
Other noncurrent liabilities	$ (146)	$ (125)
Net liability recognized	$ (146)	$ (125)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:		
Net gain (loss)	$ (24)	$ (13)

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,	
	2019	2018
Pension Plans with PBO and ABO in Excess Of Plan Assets:		
Projected benefit obligations	$ 674	$ 615
Accumulated benefit obligation	$ 669	$ 611
Plan assets	$ 528	$ 490

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%	40 % - 50%
Global equity securities	16 % - 24%	29 % - 37%	32 % - 41%
Real estate	4 % - 8%	8 % - 12%	10 % - 14%
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	3.2 %	3.2 %	3.1 %
Global equity securities	7.5 %	7.5 %	7.5 %
Real estate	5.2 %	5.2 %	5.2 %
Credit strategies	5.5 %	5.5 %	5.5 %
Weighted average	4.4 %	5.3 %	5.5 %

Fair Value Measurement of Pension Plan Assets

At December 31, 2019 and 2018, the Retirement Plan assets measured at fair value on a recurring basis consisted of the following:

	December 31,					
	2019			2018		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Asset Category:						
Interest-bearing cash	$ —	$ —	$ —	$ —	$ (6)	$ (6)
Fixed income securities:						
Corporate bonds (a)	—	—	—	57	61	118
Government bonds	—	—	—	—	25	25
Other (b)	—	—	—	—	6	6
Total assets categorized as Level 1 or 2	—	—	—	57	86	143
Assets measured at net asset value (c):						
Cash commingled trusts			10			18
Equity securities:						
Global equities			169			192
Fixed income securities:						
Corporate bonds (a)			211			137
Government bonds			50			—
Other (d)			37			—
Real estate			51			—
Total assets measured at net asset value			528			347
Total assets			$ 528			$ 490

(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.
(d) Consists primarily of high-yield bonds, emerging market debt, and bank loans.

Detailed Information Regarding Postretirement Benefits Other Than Pensions

The following OPEB information is based on a December 31, 2019 measurement date:

	Year Ended December 31,		
	2019	2018	2017
Assumptions Used to Determine Net Periodic Benefit Cost:			
Discount rate (Vistra Energy Plan)	4.35 %	3.67 %	4.11 %
Discount rate (Oncor Plan)	— %	— %	4.18 %
Discount rate (Dynegy Plan)	4.35 %	4.04 %	— %
Expected return on plan assets (EEI Union)	5.36 %	5.10 %	— %
Expected return on plan assets (EEI Salaried)	4.70 %	4.47 %	— %
Components of Net Postretirement Benefit Cost:			
Service cost	$ 2	$ 2	$ 2
Interest cost	6	5	4
Expected return on plan assets	(1)	(1)	—
Amortization of unrecognized amounts	3	3	—
Immediate postretirement benefit cost	1	—	—
Net periodic OPEB cost	$ 11	$ 9	$ 6
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:			
Net (gain) loss and prior service (credit) cost	$ —	$ (6)	$ 26
Total recognized in net periodic benefit cost and other comprehensive income	$ 11	$ 3	$ 32
Assumptions Used to Determine Benefit Obligations at Period End:			
Discount rate (Vistra Energy Plan)	3.25 %	4.35 %	3.67 %
Discount rate (Split-Participant Plan)	3.25 %	4.35 %	3.67 %
Discount rate (Dynegy Plan)	3.25 %	4.35 %	— %
Expected return on plan assets (EEI Union)	7.07 %	5.36 %	— %
Expected return on plan assets (EEI Salaried)	3.43 %	4.70 %	— %

For the year ended December 31, 2019, the net actuarial loss of $5 million was driven by losses attributable to decreasing discount rates due to changes in the corporate bond markets and plan experience different than expected, partially offset by gains attributable to actual asset performance exceeding expectations, life expectancy changes, updates to health care related assumptions and changes due to the repeal of certain Affordable Care Act fees.

For the year ended December 31, 2018, the net actuarial loss 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 period 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.

	Year Ended December 31, 2019	2018
Change in Postretirement Benefit Obligation:		
Benefit obligation at beginning of year	$ 144	$ 115
Acquisition	—	37
Service cost	2	2
Interest cost	6	5
Participant contributions	3	2
Plan amendments (a)	—	4
Curtailment	(1)	—
Actuarial (gain) loss	10	(9)
Benefits paid	(13)	(12)
Benefit obligation at end of year	$ 151	$ 144
Change in Plan Assets:		
Fair value of assets at beginning of year	$ 29	$ —
Acquisition	—	32
Employer contributions	9	8
Participant contributions	3	2
Benefits paid	(13)	(12)
Actual gain (loss) on assets	6	(1)
Fair value of assets at end of year	$ 34	$ 29
Funded Status:		
Benefit obligation	$ (151)	$ (144)
Fair value of assets	34	29
Funded status at end of year	$ (117)	$ (115)
Amounts Recognized on the Balance Sheet Consist of:		
Other noncurrent assets	$ 18	$ 14
Other current liabilities	$ (9)	$ (8)
Other noncurrent liabilities	(126)	(121)
Net liability recognized	$ (117)	$ (115)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:		
Net loss and prior service cost	$ 15	$ 15

(a) For the year ended December 31, 2018, plan amendments relate to changes in Dynegy plans and retiree medical cost structure.

The following tables provide information regarding the assumed health care cost trend rates.

	December 31, 2019	December 31, 2018
Assumed Health Care Cost Trend Rates-Not Medicare Eligible:		
Health care cost trend rate assumed for next year	6.40 %	6.70 %
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	2029	2026
Assumed Health Care Cost Trend Rates-Medicare Eligible:		
Health care cost trend rate assumed for next year (Vistra Energy Plan, EEI Union and EEI Salaried)	8.60 %	9.90 %
Health care cost trend rate assumed for next year (Oncor Plan)	8.30 %	9.90 %
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	2029	2027

Fair Value Measurement of OPEB Plan Assets

At December 31, 2019 and 2018, the Vistra Energy OPEB plan assets measured at fair value on a recurring basis totaled $34 million and $29 million, respectively, and consisted of $26 million and $21 million, respectively, of U.S equities classified as Level 1 and $8 million and $8 million, respectively, 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 rates using the Aon AA Above Median yield curve, which is based on corporate bond yields and at December 31, 2019 consisted of 361 corporate bonds with an average rating of AA using Moody's, S&P and Fitch ratings.

Contributions

Contributions to the Retirement Plan for the years ended December 31, 2019, 2018 and 2017 totaled zero, $12 million and zero, respectively, and $26 million in contributions are expected to be made in 2020. OPEB plan funding for the years ended December 31, 2019, 2018 and 2017 totaled $9 million, $8 million and $5 million, respectively, and funding in 2020 is expected to total $9 million.

Future Benefit Payments

Estimated future benefit payments to beneficiaries are as follows:

	2020	2021	2022	2023	2024	2025-29
Pension benefits	$ 59	$ 54	$ 42	$ 43	$ 42	$ 199
OPEB	$ 10	$ 10	$ 10	$ 10	$ 10	$ 43

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 formula in the Retirement Plan) 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 $27 million, $24 million and $19 million for the years ended December 31, 2019, 2018 and 2017, respectively.

18. 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:

	Year Ended December 31,		
	2019	2018	2017
Total stock-based compensation expense	$ 47	$ 73	$ 19
Income tax benefit	(9)	(15)	(7)
Stock based-compensation expense, net of tax	$ 38	$ 58	$ 12

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 granted from 2016-2018 and assumed a 1.9% dividend yield in the valuation of options granted in 2019. 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 a special dividend approved by the Board in December 2016 (see Note 14).

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 which were achieved as of December 31, 2019. Compensation cost was recognized in 2018 and 2019 based on graded vesting over 4 and 5 years since the date of issuance because we estimated achievement of the target was likely to occur.

Stock options outstanding at December 31, 2019 are all held by current employees. The following table summarizes our stock option activity:

	Year Ended December 31, 2019			
	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	14,499	$ 17.97	7.3	$ 85.1
Granted	2,103	$ 26.32		
Exercised	(1,467)	$ 13.93		
Forfeited or expired	(1,600)	$ 26.20		
Total outstanding at end of period	13,535	$ 18.73	7.3	$ 69.3
Exercisable at December 31, 2019	4,601	$ 16.14	6.6	$ 36.6

At December 31, 2019, $37 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:

	Year Ended December 31, 2019			
	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	3,226	$ 16.77	1.1	$ 73.8
Granted	989	$ 26.43		
Exercised	(1,480)	$ 18.20		
Forfeited or expired	(197)	$ 20.12		
Total outstanding at end of period	2,538	$ 20.99	0.8	$ 57.2
Expected to vest	2,485	$ 21.37	0.8	$ 56.1

At December 31, 2019, $32 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 2 years.

Performance Stock Units

In October 2017, we issued Performance Stock Units (PSUs) to certain members of management. As of December 31, 2019, 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 had not occurred. In February 2020, the final terms were established and a grant date for financial accounting purposes has occurred. Beginning March 2020, compensation cost will be recognized ratably over the remaining 13-month vesting period.

In February 2019 and February 2020**,** we issued Performance Stock Units (PSUs) to certain members of management. As of December 31, 2019, 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 had not occurred.

19. RELATED PARTY TRANSACTIONS

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 (as defined in the Registration Rights Agreement) 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, 2019, 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 8 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 Apollo or the participating broker for the 5 million shares it repurchased.

20. 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. Operational results for four facilities retired in late 2019 were recast from the MISO segment to the Asset Closure segment (see Note 4).

The Retail segment is engaged in retail sales of electricity and natural gas to residential, commercial and industrial customers. Substantially all of these activities are conducted by TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and US Gas & Electric across 19 states in the U.S.

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/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 (see Note 4). 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 the commodity risk management activities to the Asset Closure segment for the generation plants that were retired in 2018 and 2019.

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 U.S. 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.

For the year ended	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Corporate and Other (b)	Eliminations	Consolidated
Operating revenues (a):									
December 31, 2019	$ 6,872	$ 3,993	$ 2,442	$ 1,135	$ 658	$ 341	$ 338	$ (3,970)	$ 11,809
December 31, 2018	5,597	2,634	1,725	817	399	371	208	(2,607)	9,144
December 31, 2017	4,058	1,794	—	—	—	964	—	(1,386)	5,430
Depreciation and amortization:									
December 31, 2019	$ (292)	$ (508)	$ (537)	$ (208)	$ (19)	$ —	$ (76)	$ —	$ (1,640)
December 31, 2018	(318)	(416)	(413)	(152)	(9)	—	(86)	—	(1,394)
December 31, 2017	(430)	(229)	—	—	—	(1)	(40)	1	(699)
Operating income (loss):									
December 31, 2019	$ 155	$ 1,340	$ 412	$ 179	$ 52	$ (107)	$ (38)	$ —	$ 1,993
December 31, 2018	690	(70)	100	70	49	(63)	(281)	(4)	491
December 31, 2017	461	(118)	—	—	—	(68)	(78)	1	198
Interest expense and related charges:									
December 31, 2019	$ (21)	$ 8	$ (10)	$ (3)	$ (4)	$ —	$ (770)	$ 3	$ (797)
December 31, 2018	(7)	(12)	(8)	(2)	(1)	—	(613)	71	(572)
December 31, 2017	—	(21)	—	—	—	—	(252)	80	(193)
Income tax (expense) benefit:									
December 31, 2019	$ —	$ —	$ —	$ —	$ —	$ —	$ (290)	$ —	$ (290)
December 31, 2018	—	—	—	—	—	—	45	—	45
December 31, 2017	—	4	—	—	—	—	(509)	1	(504)
Net income (loss):									
December 31, 2019	$ 134	$ 1,368	$ 405	$ 188	$ 55	$ (109)	$ (1,115)	$ —	$ 926
December 31, 2018	712	(55)	100	79	48	(62)	(876)	(2)	(56)
December 31, 2017	495	(114)	—	—	—	(63)	(573)	1	(254)
Capital expenditures, including nuclear fuel and excluding LTSA prepayments:									
December 31, 2019	$ 1	$ 299	$ 69	$ 22	$ 25	$ —	$ 71	$ —	$ 487
December 31, 2018	1	283	41	10	3	—	58	—	396
December 31, 2017	—	150	—	—	—	—	26	—	176

(a) The following unrealized net gains (losses) from mark-to-market valuations of commodity positions are included in operating revenues:

For the year ended	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Corporate and Other	Eliminations (1)	Consolidated
December 31, 2019	$ 8	$ 575	$ 237	$ 102	$ 24	$ —	$ 41	$ (305)	$ 682
December 31, 2018	(12)	(483)	(50)	(40)	3	—	(15)	217	(380)
December 31, 2017	18	(305)	—	—	—	—	—	154	(133)

(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 and Other net income.

As of	Retail	ERCOT	PJM	NY/NE	MISO	Asset Closure	Corporate and Other and Eliminations	Consolidated
Total assets:								
December 31, 2019	$ 10,399	$ 10,425	$ 5,941	$ 3,060	$ 47	$ 345	$ (3,601)	$ 26,616
December 31, 2018	7,699	9,347	7,188	2,722	544	546	(2,022)	26,024

21. SUPPLEMENTARY FINANCIAL INFORMATION

Interest Expense

	Year Ended December 31,		
	2019	2018	2017
Interest paid/accrued	$ 576	$ 537	$ 213
Unrealized mark-to-market net (gains) losses on interest rate swaps	220	5	(29)
Amortization of debt issuance costs, discounts and premiums	9	—	4
Debt extinguishment (gain) loss	(21)	27	—
Capitalized interest	(12)	(12)	(7)
Other	25	15	12
Total interest expense and related charges	$ 797	$ 572	$ 193

The weighted average interest rate applicable to the Vistra Operations Credit Facilities, taking into account the interest rate swaps discussed in Note 11, was 4.03%, 4.24% and 4.38% at December 31, 2019, 2018 and 2017, respectively.

Other Income and Deductions

	Year Ended December 31,		
	2019	2018	2017
Other income:			
Office space sublease rental income (a)	$ —	$ 8	$ 11
Sale of land (b)	—	3	4
Funds released from escrow to settle pre-petition claims of our predecessor	9	—	—
Insurance settlement (b)	22	16	—
Interest income	10	18	15
All other	15	2	7
Total other income	$ 56	$ 47	$ 37
Other deductions:			
Write-off of generation equipment (b)	—	—	2
Curtailment expense (Note 4) (c)	3	—	—
All other	12	5	3
Total other deductions	$ 15	$ 5	$ 5

(a) Reported in Corporate and Other non-segment. Beginning January 1, 2019, our sublease rental income related to real estate leases is reported in SG&A expenses in the consolidated statements of operations.
(b) Reported in ERCOT segment.
(c) Reported in Asset Closure segment.

Restricted Cash

	December 31, 2019		December 31, 2018	
	Current Assets	Noncurrent Assets	Current Assets	Noncurrent Assets
Amounts related to remediation escrow accounts	$ 15	$ 28	$ —	$ —
Amounts related to restructuring escrow accounts	43	—	57	—
Amounts related to Ambit customer deposits	19	—	—	—
Amounts related to Ambit commodity trading agreement	62	—	—	—
Amounts related to Ambit letters of credit (Note 11)	8	—	—	—
Total restricted cash	$ 147	$ 28	$ 57	$ —

Remediation Escrow — During the year ended December 31, 2019, Vistra Energy transferred asset retirement obligations related to several closed plant sites to a third-party remediation company. As part of the transfers, Vistra Energy funded approximately $43 million into escrow accounts, and the funds are released to the remediation company as milestones are reached in the remediation process. Amounts contractually payable to the third party in exchange for assuming the obligations are included in other current liabilities and other noncurrent liabilities and deferred credits.

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 liabilities subject to compromise. 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, 2019, the TCEH Debtors held approximately $43 million in escrow to (1) distribute to holders of contingent and/or disputed unsecured claims that become allowed and/or (2) make further distributions to holders of previously allowed unsecured claims, if applicable. In December 2019, the Bankruptcy court entered an order, Docket No. 13982, sustaining the TCEH Debtors' objection to and liquidating the manifested and unmanifested asbestos claims. As of this filing, the TCEH Debtors believe they have resolved the remaining contingent and/or disputed unsecured claims, and are undertaking the necessary steps to modify the claims register accordingly and make a final distribution from the escrow to holders of allowed claims in the near term. The claims that remained unresolved as of December 31, 2019 and the related escrow balance are recorded in Vistra Energy's consolidated balance sheet as other current liabilities and current restricted cash, respectively. All non-priority unsecured claims, including asbestos claims arising before the Petition Date, will be satisfied solely from the approximately $43 million in escrow.

Trade Accounts Receivable

	December 31,	
	2019	2018
Wholesale and retail trade accounts receivable	$ 1,401	$ 1,106
Allowance for uncollectible accounts	(36)	(19)
Trade accounts receivable — net (a)	$ 1,365	$ 1,087

(a) At December 31, 2019, includes $175 million of trade accounts receivable related to operations acquired in the Ambit and Crius Transactions.

Gross trade accounts receivable at December 31, 2019 and 2018 included unbilled retail revenues of $494 million and $350 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Year Ended December 31,		
	2019	2018	2017
Allowance for uncollectible accounts receivable at beginning of period	$ 19	$ 14	$ 10
Increase for bad debt expense	82	56	43
Decrease for account write-offs	(65)	(51)	(39)
Allowance for uncollectible accounts receivable at end of period	$ 36	$ 19	$ 14

Inventories by Major Category

	December 31, 2019	December 31, 2018
Materials and supplies	$ 278	$ 286
Fuel stock	172	115
Natural gas in storage	19	11
Total inventories	$ 469	$ 412

Investments

	December 31, 2019	December 31, 2018
Nuclear plant decommissioning trust	$ 1,451	$ 1,170
Assets related to employee benefit plans (Note 17)	37	31
Land	49	49
Total investments	$ 1,537	$ 1,250

Investment in Unconsolidated Subsidiary

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, 2019 and 2018, our investment in NELP totaled $123 million and $129 million, respectively. Our risk of loss related to our equity method investment is limited to our investment balance.

Equity earnings related to our investment in NELP totaled $14 million and $17 million for the years ended December 31, 2019 and 2018, respectively, recorded in equity in earnings of unconsolidated investment in our consolidated statements of operations. We received distributions totaling $22 million and $17 million for the years ended December 31, 2019 and 2018, respectively.

In December 2019, Dynegy Northeast Generation GP, Inc. and Dynegy Northeast Associates LP, Inc., indirect subsidiaries of Vistra Energy, entered into a transaction agreement with NELP wherein the indirect subsidiaries of Vistra will redeem their ownership interest in the NELP partnership in exchange for 100% ownership interest in New Jersey Energy Associates, the holding company which owns the Sayreville facility. As a result of the agreement, Vistra will indirectly own 100% of the Sayreville facility and will no longer have an ownership interest in the Bellingham NEA facility. The agreement was approved by FERC on February 25, 2020, and the transaction is expected to close on March 2, 2020.

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 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, including gains and losses associated with the trust fund assets and the decommissioning liability, are offset by a corresponding change in a regulatory asset/liability (currently a regulatory liability reported in other noncurrent liabilities and deferred credits) 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 the fair market value of investments in the fund follows:

	Year Ended December 31,	
	2019	2018
Debt securities (a)	$ 521	$ 443
Equity securities (b)	930	727
Total	$ 1,451	$ 1,170

(a) 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. 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 3.42% and 3.69% at December 31, 2019 and 2018, respectively, and an average maturity of 9 years and 8 years at December 31, 2019 and 2018, respectively.
(b) 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 EAFE Index for non-U.S. equity investments.

Debt securities held at December 31, 2019 mature as follows: $170 million in one to five years, $147 million in five to 10 years and $204 million after 10 years.

The following table summarizes proceeds from sales of securities and investments in new securities.

	Year Ended December 31,		
	2019	2018	2017
Proceeds from sales of securities	$ 431	$ 252	$ 252
Investments in securities	$ (453)	$ (274)	$ (272)

Property, Plant and Equipment

	December 31,	
	2019	2018
Power generation and structures	$ 15,205	$ 14,604
Land	622	642
Office and other equipment	164	182
Total	15,991	15,428
Less accumulated depreciation	(2,553)	(1,284)
Net of accumulated depreciation	13,438	14,144
Finance lease right-of-use assets	59	—
Nuclear fuel (net of accumulated amortization of $216 million and $189 million)	197	191
Construction work in progress	220	277
Property, plant and equipment — net	$ 13,914	$ 14,612

Depreciation expenses totaled $1.300 billion, $1.024 billion and $236 million for the years ended December 31, 2019, 2018 and 2017, 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. The estimated remaining useful lives range from 1 to 34 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, remediation or closure of coal ash basins, and generation plant 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. We have also identified conditional AROs for asbestos removal and disposal, which are specific to certain generation assets. However, because the period of remediation is indeterminable no removal liabilities have been recognized.

At December 31, 2019, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.320 billion, which is lower than 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 liability has been recorded to our consolidated balance sheet of $131 million in other noncurrent liabilities and deferred credits.

The following table summarizes the changes to these obligations, reported as AROs (current and noncurrent liabilities) in our consolidated balance sheets, for the years ended December 31, 2019, 2018 and 2017:

	Nuclear Plant Decommissioning	Mining Land Reclamation	Coal Ash and Other	Total
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
Additions:				
Accretion	44	22	31	97
Adjustment for change in estimates	—	16	(1)	15
Adjustment for obligations assumed through acquisitions	—	—	(3)	(3)
Reductions:				
Payments	—	(70)	(39)	(109)
Liability transfers (c)	—	—	(135)	(135)
Liability at December 31, 2019	1,320	410	508	2,238
Less amounts due currently	—	(89)	(52)	(141)
Noncurrent liability at December 31, 2019	$ 1,320	$ 321	$ 456	$ 2,097

(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).
(c) Represents ARO transferred to a third-party for remediation. Any remaining unpaid third-party obligation has been reclassified to other current liabilities and other noncurrent liabilities and deferred credits in our consolidated balance sheets.

Other Noncurrent Liabilities and Deferred Credits

The balance of other noncurrent liabilities and deferred credits consists of the following:

	December 31, 2019	December 31, 2018
Retirement and other employee benefits	$ 295	$ 270
Identifiable intangible liabilities (Note 6)	286	401
Regulatory liability	131	—
Finance lease liabilities	78	—
Uncertain tax positions, including accrued interest	10	4
Liability for third-party remediation	41	—
Other accrued expenses	148	66
Total other noncurrent liabilities and deferred credits	$ 989	$ 741

Fair Value of Debt

		December 31, 2019		December 31, 2018	
Long-term debt (see Note 11):	**Fair Value Hierarchy**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt under the Vistra Operations Credit Facilities	Level 2	$ 2,715	$ 2,717	$ 5,820	$ 5,599
Vistra Operations Senior Notes	Level 2	6,620	6,926	987	963
Vistra Energy Senior Notes	Level 2	774	772	3,819	3,765
7.000% Amortizing Notes	Level 2	—	—	23	24
Forward Capacity Agreements	Level 3	155	155	221	221
Equipment Financing Agreements	Level 3	87	87	102	102
Mandatorily redeemable subsidiary preferred stock	Level 2	—	—	70	70
Building Financing	Level 2	16	16	23	21
Other debt	Level 3	12	12	—	—

We determine fair value in accordance with accounting standards as discussed in Note 15. 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 consolidated statements of cash flows to the amounts reported in our balance sheets at December 31, 2019 and 2018:

	December 31,	
	2019	**2018**
Cash and cash equivalents	$ 300	$ 636
Restricted cash included in current assets	147	57
Restricted cash included in noncurrent assets	28	—
Total cash, cash equivalents and restricted cash	$ 475	$ 693

The following table summarizes our supplemental cash flow information for the years ended December 31, 2019, 2018 and 2017, respectively.

	Year Ended December 31,		
	2019	**2018**	**2017**
Cash payments related to:			
Interest paid	$ 525	$ 651	$ 245
Capitalized interest	(12)	(12)	(7)
Interest paid (net of capitalized interest)	$ 513	$ 639	$ 238
Income taxes paid / (refunds received) (a)	$ (76)	$ 67	$ 63
Noncash investing and financing activities:			
Construction expenditures (b)	$ 50	$ 79	$ 12
Shares issued for tangible equity unit contracts (Note 14)	$ 446	$ —	$ —
Land transferred with liability transfers	$ 16	$ —	$ —
Vistra Energy common stock issued in the Merger (Notes 2 and 14)	$ —	$ 2,245	$ —

(a) For the year ended December 31, 2019, we paid state income taxes of $39 million and received federal tax refunds of $115 million.

(b) 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.

	Quarter Ended			
	March 31	June 30	September 30	December 31
2019 (a):				
Operating revenues	$ 2,923	$ 2,832	$ 3,194	$ 2,860
Operating income	$ 490	$ 729	$ 440	$ 334
Net income	$ 224	$ 354	$ 114	$ 234
Net income attributable to Vistra Energy	$ 225	$ 356	$ 113	$ 234
Net income per weighted average share of common stock outstanding — basic	$ 0.45	$ 0.71	$ 0.23	$ 0.49
Net income per weighted average share of common stock outstanding — diluted	$ 0.44	$ 0.70	$ 0.23	$ 0.49
2018 (b):				
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)

(a) For the year ended December 31, 2019, reflects the results of operations acquired in the Crius and Ambit Transactions.
(b) For the year ended December 31, 2018, reflects the results of operations acquired in the Merger.

22. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our senior unsecured 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 11 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.

Parent received $3.890 billion, $4.668 billion and $1.505 billion in dividends from its consolidated subsidiaries in the years ended December 31, 2019, 2018 and 2017, respectively.

Condensed Consolidating Statements of Operations
for the Year Ended December 31, 2019
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues	$ —	$ 11,572	$ 528	$ (291)	$ 11,809
Fuel, purchased power costs and delivery fees	—	(5,613)	(297)	168	(5,742)
Operating costs	—	(1,465)	(65)	—	(1,530)
Depreciation and amortization	(7)	(1,551)	(82)	—	(1,640)
Selling, general and administrative expenses	(62)	(851)	(115)	124	(904)
Operating income (loss)	(69)	2,092	(31)	1	1,993
Other income	12	51	1	(8)	56
Other deductions	—	(15)	—	—	(15)
Interest expense and related charges	(88)	(689)	(27)	7	(797)
Impacts of Tax Receivable Agreement	(37)	—	—	—	(37)
Equity in earnings of unconsolidated investment	—	16	—	—	16
Income (loss) before income taxes	(182)	1,455	(57)	—	1,216
Income tax (expense) benefit	42	(345)	13	—	(290)
Equity in earnings (loss) of subsidiaries, net of tax	1,068	(42)	—	(1,026)	—
Net income (loss)	928	1,068	(44)	(1,026)	926
Net loss attributable to noncontrolling interest	—	—	2	—	2
Net income (loss) attributable to Vistra Energy	$ 928	$ 1,068	$ (42)	$ (1,026)	$ 928

Condensed Consolidating Statements of Operations
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) benefit	282	(284)	47	—	45
Equity in earnings (losses) 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 Consolidating Statements of Operations
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	4	33	—	—	37
Other deductions	—	(5)	—	—	(5)
Interest expense and related charges	—	(193)	—	—	(193)
Impacts of Tax Receivable Agreement	213	—	—	—	213
Income before income taxes	170	80	—	—	250
Income tax (expense) benefit	80	(584)	—	—	(504)
Equity in earnings (losses) of subsidiaries, net of tax	(504)	—	—	504	—
Net income (loss)	$ (254)	$ (504)	$ —	$ 504	$ (254)

Condensed Consolidating Statements of Comprehensive Income (Loss)
for the Year Ended December 31, 2019
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net income (loss)	$ 928	$ 1,068	$ (44)	$ (1,026)	$ 926
Other comprehensive income (loss), net of tax effects:					
Effect related to pension and other retirement benefit obligations	—	(8)	—	—	(8)
Total other comprehensive income	—	(8)	—	—	(8)
Comprehensive income (loss)	928	1,060	(44)	(1,026)	918
Comprehensive loss attributable to noncontrolling interest	—	—	2	—	2
Comprehensive income (loss) attributable to Vistra Energy	$ 928	$ 1,060	$ (42)	$ (1,026)	$ 920

Condensed Consolidating Statements of 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 Consolidating Statements of 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 Consolidating Statements of Cash Flows
for the Year Ended December 31, 2019
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows — operating activities:					
Cash provided by (used in) operating activities	$ (58)	$ 2,702	$ 92	$ —	$ 2,736
Cash flows — investing activities:					
Capital expenditures, including LTSA prepayments	(36)	(471)	(13)	—	(520)
Nuclear fuel purchases	—	(89)	—	—	(89)
Development and growth expenditures	—	(104)	—	—	(104)
Ambit acquisition (net of cash acquired)	—	(506)	—	—	(506)
Crius acquisition (net of cash acquired)	—	(374)	—	—	(374)
Proceeds from sales of nuclear decommissioning trust fund securities	—	431	—	—	431
Investments in nuclear decommissioning trust fund securities	—	(453)	—	—	(453)
Proceeds from sales of environmental allowances	—	197	—	—	197
Purchases of environmental allowances	—	(321)	(1)	—	(322)
Dividend received from subsidiaries	3,890	—	—	(3,890)	—
Other, net	—	23	—	—	23
Cash provided by (used in) investing activities	3,854	(1,667)	(14)	(3,890)	(1,717)
Cash flows — financing activities:					
Issuances of long-term debt	—	6,507	—	—	6,507
Repayments/repurchases of debt	(2,903)	(4,139)	(67)	—	(7,109)
Net borrowings under accounts receivable securitization program	—	—	111	—	111
Borrowings under Revolving Credit Facility	—	650	—	—	650
Repayments under Revolving Credit Facility	—	(300)	—	—	(300)
Debt tender offer and other financing fees	(123)	(80)	—	—	(203)
Stock repurchase	(656)	—	—	—	(656)
Cash dividends paid	(243)	(3,890)	—	3,890	(243)
Other, net	—	6	—	—	6
Cash provided by (used in) financing activities	(3,925)	(1,246)	44	3,890	(1,237)
Net change in cash, cash equivalents and restricted cash	(129)	(211)	122	—	(218)
Cash, cash equivalents and restricted cash — beginning balance	228	453	12	—	693
Cash, cash equivalents and restricted cash — ending balance	$ 99	$ 242	$ 134	$ —	$ 475

Condensed Consolidating Statements of 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 — investing activities:					
Capital expenditures, including LTSA prepayments	(24)	(351)	(3)	—	(378)
Nuclear fuel purchases	—	(118)	—	—	(118)
Development and growth expenditures	—	(31)	(3)	—	(34)
Cash acquired in the Merger	—	445	—	—	445
Proceeds from sales of nuclear decommissioning trust fund securities	—	252	—	—	252
Investments in nuclear decommissioning trust fund securities	—	(274)	—	—	(274)
Proceeds from sales of environmental allowances	—	1	—	—	1
Purchases of environmental allowances	—	(5)	—	—	(5)
Dividend received from subsidiaries	4,668	—	—	(4,668)	—
Other, net	(1)	11	—	—	10
Cash provided by (used in) investing activities	4,643	(70)	(6)	(4,668)	(101)
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 dividends paid	—	(4,668)	—	4,668	—
Debt tender offer and other financing fees	(179)	(57)	—	—	(236)
Stock repurchase	(763)	—	—	—	(763)
Other, net	12	—	—	—	12
Cash provided by (used in) financing activities	(5,473)	(2,257)	339	4,668	(2,723)
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 Consolidating Statements of 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 — 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)
Proceeds from sales of environmental allowances	—	1	—	—	1
Purchases of environmental allowances	—	(3)	—	—	(3)
Dividend received from subsidiaries	1,505	—	—	(1,505)	—
Other, net	—	16	—	—	16
Cash provided by (used in) investing activities	1,175	(397)	—	(1,505)	(727)
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)
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 Consolidating Balance Sheet
as of December 31, 2019
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	56	$ 199	$ 45	$ —	$ 300
Restricted cash	43	15	89	—	147
Advances to affiliates	—	56	—	(56)	—
Trade accounts receivable — net	5	705	781	(126)	1,365
Accounts receivable — affiliates	—	275	—	(275)	—
Notes due from affiliates	—	122	—	(122)	—
Income taxes receivable	—	—	—	—	—
Inventories	—	436	33	—	469
Commodity and other derivative contractual assets	—	1,326	14	(7)	1,333
Margin deposits related to commodity contracts	—	191	11	—	202
Prepaid expense and other current assets	100	172	27	(1)	298
Total current assets	204	3,497	1,000	(587)	4,114
Restricted cash	—	28	—	—	28
Investments	—	1,500	37	—	1,537
Investment in unconsolidated subsidiary	—	124	—	—	124
Investment in affiliated companies	8,364	697	—	(9,061)	—
Operating lease right-of-use assets	—	32	12	—	44
Property, plant and equipment — net	4	13,402	508	—	13,914
Goodwill	—	2,339	214	—	2,553
Identifiable intangible assets — net	49	2,435	264	—	2,748
Commodity and other derivative contractual assets	—	134	2	—	136
Accumulated deferred income taxes	729	398	—	(61)	1,066
Other noncurrent assets	67	269	16	—	352
Total assets	$ 9,417	$ 24,855	$ 2,053	$ (9,709)	$ 26,616
LIABILITIES AND EQUITY					
Current liabilities:					
Short-term borrowings	$ —	$ 350	$ —	$ —	$ 350
Accounts receivable securitization program	—	—	450	—	450
Advances from affiliates	—	—	57	(57)	—
Long-term debt due currently	87	185	6	(1)	277
Trade accounts payable	1	855	211	(120)	947
Accounts payable — affiliates	145	—	127	(272)	—
Notes due to affiliates	—	—	122	(122)	—
Commodity and other derivative contractual liabilities	—	1,505	31	(7)	1,529
Margin deposits related to commodity contracts	—	8	—	—	8
Accrued taxes	1	—	—	—	1
Accrued taxes other than income	—	188	12	—	200
Accrued interest	11	138	8	(6)	151

Condensed Consolidating Balance Sheet
as of December 31, 2019
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Asset retirement obligations	—	141	—	—	141
Operating lease liabilities	—	10	4	—	14
Other current liabilities	46	402	58	—	506
Total current liabilities	291	3,782	1,086	(585)	4,574
Long-term debt, less amounts due currently	689	9,385	28	—	10,102
Operating lease liabilities	—	33	8	—	41
Commodity and other derivative contractual liabilities	—	392	5	(1)	396
Accumulated deferred income taxes	—	—	63	(61)	2
Tax Receivable Agreement obligation	455	—	—	—	455
Asset retirement obligations	—	2,084	13	—	2,097
Other noncurrent liabilities and deferred credits	22	815	153	(1)	989
Total liabilities	1,457	16,491	1,356	(648)	18,656
Total stockholders' equity	7,960	8,364	696	(9,061)	7,959
Noncontrolling interest in subsidiary	—	—	1	—	1
Total liabilities and equity	$ 9,417	$ 24,855	$ 2,053	$ (9,709)	$ 26,616

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

Condensed Consolidating Balance Sheet
as of December 31, 2018
(Millions of Dollars)

	Parent (Issuer)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
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
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
Other noncurrent liabilities and deferred credits	20	581	140	—	741
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

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 (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) in effect at December 31, 2019. On the Ambit Acquisition Date, we completed the Ambit Transaction. Vistra Energy is currently in the process of evaluating the internal controls of the acquired business and integrating it into our existing operations. As permitted by the SEC, management has elected to exclude Ambit Holdings, LLC from its assessment of the effectiveness of its internal controls over financial reporting as of December 31, 2019. Based on the evaluation performed, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of that date.

Other than the changes resulting from the Ambit Transaction, there have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) 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 of the effectiveness of the company's internal control over financial reporting as of December 31, 2019 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, 2019 Vistra Energy Corp.'s internal control over financial reporting was effective.

On November 1, 2019, an indirect, wholly owned subsidiary of Vistra Energy Corp. acquired Ambit Holdings, LLC, as further described in Note 2, *Acquisitions, Merger Transaction and Business Combination Accounting*. Ambit Holdings, LLC's financial statements comprised approximately 3% of the company's total assets as of December 31, 2019 and approximately 2% and less than 1%, respectively of the company's total revenues and net income for the year ended December 31, 2019. As of December 31, 2019, we are in the process of evaluating the internal controls of the acquired business and integrating it into our existing operations. As permitted by the SEC, management has elected to exclude Ambit Holdings, LLC from its assessment of the effectiveness of its internal control over financial reporting as of December 31, 2019.

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/ DAVID A. CAMPBELL
Curtis A. Morgan	David A. Campbell
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

February 28, 2020

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, 2019, 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, 2019, 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, 2019, of the Company and our report dated February 28, 2020, expressed an unqualified opinion on those financial statements.

As described in Management's Annual Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Ambit Holdings, LLC, which was acquired on November 1, 2019 and whose financial statements constitute approximately 3% of total assets, approximately 2% of revenues, and less than 1% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2019. Accordingly, our audit did not include the internal control over financial reporting at Ambit Holdings, LLC.

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 Management's 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, Texas
February 28, 2020

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 will disclose such events within four business days following the date of the amendment or waiver, 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 2020 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 2020 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 2020 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 2020 Annual Meeting of Stockholders.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 2020 Annual Meeting of Stockholders.

PART IV

Item 15. EXHIBITS AND 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, 2019

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 for Dynegy Inc. (filed on May 21, 2013)	4.1	—	2023 Notes Indenture, dated May 20, 2013, among Dynegy, the Subsidiary Guarantors and the Trustee
4.2	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
4.3	001-33443 Form 8-K for Dynegy Inc. (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
4.4	001-33443 Form 8-K for Dynegy Inc. (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
4.5	001-33443 Form 10-Q for Dynegy Inc. (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
4.6	001-33443 Form 10-Q for Dynegy Inc. (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

Exhibits	Previously Filed With File Number*	As Exhibit		
4.7	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
4.8	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
4.9	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
4.10	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
4.11	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.1	—	Tenth Supplemental Indenture to the 2023 Notes Indenture, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.12	**		—	Eleventh Supplemental Indenture to the 2023 Notes Indenture, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.13	001-33443 Form 8-K for Dynegy Inc. (filed on May 21, 2013)	4.1	—	Form of 5.875% Senior Note due 2023
4.14	001-33443 Form 8-K for Dynegy Inc. (filed on October 11, 2016)	4.1	—	2025 Notes Indenture, dated October 11, 2016, between Dynegy and the Trustee
4.15	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
4.16	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
4.17	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
4.18	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
4.19	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
4.20	001-33443 Form 10-Q for Dynegy Inc. (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.3	—	Sixth Supplemental Indenture to the 2025 Notes Indenture, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.21	**		—	Seventh Supplemental Indenture to the 2025 Notes Indenture, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.22	001-33443 Form 8-K (filed on October 11, 2016)	4.1	—	Form of 8.000% Senior Note due 2025
4.23	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
4.24	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
4.25	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)
4.26	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
4.27	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
4.28	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
4.29	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.4	—	Fourth Supplemental Indenture to the 2026 Notes Indenture, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.30	**		—	Fifth Supplemental Indenture to the 2026 Notes Indenture, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.31	001-33443 Form 8-K (filed on August 21, 2017)	4.1	—	Form of 8.125% Senior Note due 2026
4.32	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
4.33	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)
4.34	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)
4.35	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.5	—	First Supplemental Indenture for the 5.500% Senior Notes due 2026, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.36	**		—	Second Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.37	001-38086 Form 8-K (filed on February 6, 2019)	4.1	—	Indenture for 5.625% 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

Exhibits	Previously Filed With File Number*	As Exhibit		
4.38	001-38086 Form 8-K (filed on February 6, 2019)	4.2	—	Form of Rule 144A Global Security for 5.625% Senior Note due2027 (included in Exhibit 4.1)
4.39	001-38086 Form 8-K (filed on February 6, 2019)	4.3	—	Form of Regulation S Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)
4.40	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.6	—	First Supplemental Indenture for the 5.625% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.41	**		—	Second Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.42	001-38086 Form 8-K (filed on June 24, 2019)	4.1	—	Indenture for 5.00% Senior Notes due 2027, dated as of June 21, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.43	001-38086 Form 8-K (filed on June 24, 2019)	4.2	—	Form of Rule 144A Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.44	001-38086 Form 8-K (filed on June 24, 2019)	4.3	—	Form of Regulation S Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.45	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.7	—	First Supplemental Indenture for the 5.000% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.46	**		—	Second Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.47	001-38086 Form 8-K (filed on June 17, 2019)	4.1	—	Indenture, dated as of June 11, 2019, between Vistra Operations Company LLC, as Issuer, the and Wilmington Trust, National Association, as Trustee
4.48	001-38086 Form 8-K (filed on June 17, 2019)	4.2	—	Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes Due 2029, dated as of June 11, 2019, 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 June 17, 2019)	4.3	—	Form of Rule 144A Global Security for 3.55% Senior Notes due 2024 (included in Exhibit 4.2)
4.50	001-38086 Form 8-K (filed on June 17, 2019)	4.4	—	Form of Rule 144A Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)
4.51	001-38086 Form 8-K (filed on June 17, 2019)	4.5	—	Form of Regulation S Global Security for 3.55% Senior Notes due 2024 (included in Exhibit 4.2)
4.52	001-38086 Form 8-K (filed on June 17, 2019)	4.6	—	Form of Regulation S Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.53	001-33443 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.8	—	Second Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of August 30, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.54	001-38086 Form 8-K (filed on November 21, 2019)	4.1	—	Third Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of October 25, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, Subsidiary Guarantors and the Trustee
4.55	001-38086 Form 8-K (filed on November 21, 2019)	4.2	—	Fourth Supplemental Indenture, dated as of November 15, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.56	001-38086 Form 8-K (filed on November 21, 2019)	4.3	—	Form of Rule 144A Global Security for 3.70% Senior Note due 2027 (included in Exhibit 4.2)
4.57	001-38086 Form 8-K (filed on November 21, 2019)	4.4	—	Form of Regulation S Global Security for 3.70% Senior Note due 2027 (included in Exhibit 4.2)
4.58	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
4.59	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
4.60	001-38086 Form 8-K (filed on April 5, 2019)	4.1	—	First Amendment to Purchase and Sale Agreement, dated as of April 1, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.61	001-38086 Form 8-K (filed on April 5, 2019)	4.2	—	First Amendment to Receivables Purchase Agreement, dated as of April 1, 2019, 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
4.62	001-33443 Form 10-Q (Quarter ended June 30, 2019) (filed on August 2, 2019)	4.12	—	Second Amendment to Purchase and Sale Agreement, dated as of June 3, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.63	001-33443 Form 10-Q (Quarter ended June 30, 2019) (filed on August 2, 2019)	4.13	—	Second Amendment to Receivables Purchase Agreement, dated as of June 3, 2019, 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
4.64	001-38086 Form 8-K (filed on July 19, 2019)	4.1	—	Third Amendment to Purchase and Sale Agreement, dated as of July 15, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser

Exhibits	Previously Filed With File Number*	As Exhibit		
4.65	001-38086 Form 8-K (filed on July 19, 2019)	4.2	—	Third Amendment to Receivables Purchase Agreement, dated as of July 15, 2019, 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
4.66	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
4.67	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
4.68	001-33443 Form of 8-K (filed on February 7, 2017)	4.1	—	Form of Warrant
4.69	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
4.70	**		—	Description of Capital Stock
(10)	**Material Contracts**			
	Management Contracts; Compensatory Plans, Contracts and Arrangements			
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	001-33443 Form10-K (Year ended December 31, 2018) (filed on February 28, 2019)	10.6	—	Amended and Restated 2016 Omnibus Incentive Plan, effective as of February 26, 2019
10.7	001-38086 Form 8-K (filed on May 23, 2019)	10.1	—	Amended and Restated 2016 Omnibus Incentive Plan, effective as of May 20, 2019
10.8	001-33443 Form10-K (Year ended December 31, 2018) (filed on February 28, 2019)	10.7	—	Vistra Energy Equity Deferred Compensation Plan for Certain Directors

Exhibits	Previously Filed With File Number*	As Exhibit		
10.9	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.
10.10	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.
10.11	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.
10.12	001-33443 Form 10-Q (Quarter ended March 31, 2019) (filed on May 3, 2019)	10.5	—	Amended and Restated Employment Agreement, dated May 1, 2019, between James A. Burke and Vistra Energy Corp.
10.13	001-38086 Form 8-K (filed May 28, 2019)	10.1	—	Employment Agreement, dated May 28, 2019, by and between David Campbell and Vistra Energy Corp.
10.14	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.
10.15	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.
10.16	001-33443 Form 10-K (Year ended December 31, 2018) (filed on February 25, 2019)	10.18	—	Agreement between Scott A. Hudson, Vistra Energy Corp. and TXU Retail Service Company
10.17	001-33443 Form 10-K (Year ended December 31, 2018) (filed on February 25, 2019)	10.19	—	Agreement between Stephen J. Muscato, Vistra Energy Corp. and Luminant Energy Company LLC
10.18	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.26	—	Form of indemnification agreement with directors
10.19	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			
10.20	333-215288 Form S-1 (filed December 23, 2016)	10.1	—	Credit Agreement, dated as of October 3, 2017
10.21	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.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.22	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.
10.23	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.
10.24	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.
10.25	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.
10.26	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.
10.27	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.
10.28	001-38086 Form 8-K (filed April 4, 2019)	10.4	—	Eighth Amendment to Credit Agreement, dated March 29, 2019, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties (as defined in the Vistra Operations Credit Agreement) party thereto, Bank of Montreal, Chicago Branch, as new Revolving Loan Lender, Revolving Letter of Credit Issuer and Joint Lead Arranger, the various other Lenders and Letter of Credit Issuers party thereto, and Credit Suisse as Administrative Agent and Collateral Agent
10.29	001-38086 Form 8-K (filed May 29, 2019)	10.1	—	Ninth Amendment to Credit Agreement, dated May 29, 2019, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties (as defined in the Vistra Operations Credit Agreement) party thereto, Sun Trust Bank, as incremental Revolving Loan Lender, and Credit Suisse AG, Cayman Island Branch, as Administrative Agent and Collateral Agent
10.30	001-38086 Form 8-K (filed on November 21, 2019)	10.1	—	Tenth Amendment to the Credit Agreement, dated November 15, 2019, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, the other Credit Parties (as defined in the Credit Agreement) party thereto, Credit Suisse AG, Cayman Islands Branch (as the 2019 Incremental Term Loan Lender and as Administrative Agent and as Collateral Agent), and the other Lenders party thereto
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

Exhibits	Previously Filed With File Number*	As Exhibit		
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 June 7, 2019)	10.1	—	Purchase Agreement, dated June 4, 2019, 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
10.34	001-38086 Form 8-K (filed on June 7, 2019)	10.2	—	Purchase Agreement, dated June 6, 2019, by and among Vistra Operations Company LLC and Goldman Sachs & Co. LLC, on and behalf of itself and the several Initial Purchasers named in Schedule I to the Purchase Agreement
10.35	001-38086 Form 8-K (filed on November 13, 2019)	10.1	—	Purchase Agreement, dated November 6, 2019, by and among Vistra Operations Company LLC and J.P. Morgan Securities LLC, on behalf of itself and the several Initial Purchases named in Schedule I to the Purchase Agreement
10.36	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.
10.37	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).
10.38	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.
10.39	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			
10.40	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
10.41	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
10.42	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.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.43	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
10.44	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.), EFH Corp., Energy Future Intermediate Holding Company LLC, EFI Finance Inc. and EFH Merger Co. LLC, dated as of October 3, 2016
10.45	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
10.46	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
10.47	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
10.48	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
10.49	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)
10.50	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
10.51	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
(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 David A. Campbell, principal financial officer of Vistra Energy Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32)	**Section 1350 Certifications**			

Exhibits	Previously Filed With File Number*	As Exhibit		
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 David A. Campbell, 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	**		—	The following financial information from Vistra Energy Corp.'s Annual Report on Form 10-K for the year ended December 31, 2019 formatted in Inline XBRL (Extensible Business Reporting Language) includes: (i) the Consolidated Statements of Operations, (ii) the Consolidated Statements of Comprehensive Income (Loss), (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statement of Changes in Equity (vi) the Notes to the Consolidated Financial Statements.
101.SCH	**		—	XBRL Taxonomy Extension Schema Document
101.CAL	**		—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	**		—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	**		—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	**		—	XBRL Taxonomy Extension Presentation Linkbase Document
104			—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

*   Incorporated herein by reference
**   Filed herewith
***   Furnished herewith

Item 16. FORM 10-K SUMMARY

None.

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, 2020 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, 2020
/s/ DAVID A. CAMPBELL (David A. Campbell, Executive Vice President and Chief Financial Officer)	Principal Financial Officer	February 28, 2020
/s/ CHRISTY DOBRY (Christy Dobry, Vice President and Controller)	Principal Accounting Officer	February 28, 2020
/s/ SCOTT B. HELM (Scott B. Helm, Chairman of the Board)	Chairman of the Board and Director	February 28, 2020
/s/ HILARY E. ACKERMANN (Hilary E. Ackermann)	Director	February 28, 2020
/s/ ARCILIA C. ACOSTA (Arcilia C. Acosta)	Director	February 28, 2020
/s/ GAVIN R. BAIERA (Gavin R. Baiera)	Director	February 28, 2020
/s/ PAUL M. BARBAS (Paul M. Barbas)	Director	February 28, 2020
/s/ LISA M. CRUTCHFIELD (Lisa M. Crutchfield)	Director	February 28, 2020
/s/ BRIAN K. FERRAIOLI (Brian K. Ferraioli)	Director	February 28, 2020
/s/ JEFF D. HUNTER (Jeff D. Hunter)	Director	February 28, 2020
(Geoffrey D. Strong)	Director	February 28, 2020
/s/ JOHN R. SULT (John R. Sult)	Director	February 28, 2020
(Bruce Zimmerman)	Director	February 28, 2020

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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)*
Arcilia C. Acosta (2,3)
Gavin R. Baiera (2)*
Paul M. Barbas (3)*
Lisa Crutchfield (3,4)
Brian K. Ferraioli (1)*
Scott B. Helm, Chairman of the Board of Directors
Jeff D. Hunter (1,4)
Curtis A. Morgan
Geoffrey D. Strong (3)
John R. Sult (1,2)
Bruce E. Zimmerman (1)

[1] Audit Committee
[2] Compensation Committee
[3] Nominating and Governance Committee
[4] Sustainability and Risk Committee
* Committee Chair

† As of March 30, 2020. Geoffrey D. Strong and Bruce E. Zimmerman will serve on the Board of Directors and their respective committees until April 29, 2020. 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 Corp. | 6555 Sierra Drive, Irving, Texas 75039 | www.vistraenergy.com