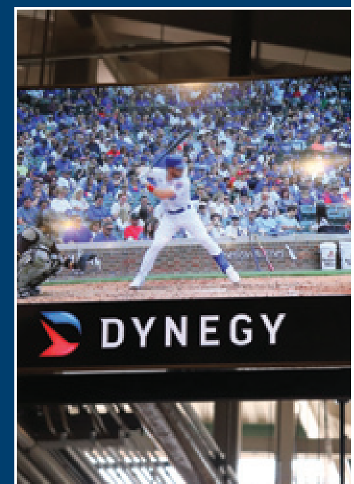
VISTRA

ANNUAL REPORT

Powering a Better Way Forward: Chicago

For decades, one of Vistra's premier retail brands, Dynegy, has served millions of customers across the Midwest and Northeast, and we're excited to power some of Chicago's most beloved and iconic sites, including Wrigley Field and Willis Tower.



Wrigley Field

Dynegy is the Official and Exclusive Energy Provider for the Chicago Cubs and Wrigley Field. Dynegy is committed to delivering best-in-class service and powering the gameday experience for fans visiting Chicago's beloved Wrigley Field. Dynegy understands the unique operational needs of professional sports facilities and is committed to creating tailored solutions that work for each of its customers.

Willis Tower

Sustainability is a shared top priority for Dynegy and Chicago's iconic Willis Tower. As the retail electric supplier for the 110-story tower, Dynegy provides 100% renewable electricity, supporting the building's sustainability goals. Dynegy is proud to power the historic Willis Tower and serve the millions of people who work and visit it each year.

> **Vistra has established itself as a leader in ESG and the clean energy transition with our Vistra Zero carbon-free generation portfolio and our many green retail products and solutions we offer to customers.**

Curt Morgan
Chief Executive Officer

Dear Fellow Vistra Stockholders,

There is no doubt that 2021 was a challenging year; however, in many ways, 2021 was also a pivotal one. We began the year facing the hardships presented by Winter Storm Uri (Uri), but with our team of dedicated employees, we came together to not only confront and mitigate the impact but also grow from the experience. Back in 2016, when Vistra emerged from bankruptcy we embarked on a strategy emphasizing a strong balance sheet as one of the cornerstones of the company. That strategic priority enabled us to withstand Uri and get back on track in a relatively short period of time.

After understanding the full impact of Uri, we began a comprehensive process in the second quarter of 2021 to review our strategic direction and approach to capital allocation. As a result of this process, we identified and prioritized four key strategic imperatives:

1. Accelerating our zero-carbon growth pipeline with cost-effective capital
2. Returning significant capital to stockholders from our core business
3. Maintaining a strong balance sheet
4. Driving long-term, sustainable value through Vistra's integrated business model

By year-end, we had delivered squarely on each of these four strategic imperatives, and I'll touch on each in the following pages to highlight our performance in 2021 and the prospects for the future of our company.

Accelerating our Zero-Carbon Growth Pipeline with Cost-Effective Capital

Vistra has established itself as a leader in ESG and the clean energy transition with our Vistra Zero carbon-free generation portfolio and our many green retail products and solutions we offer to customers. We continue to focus on opportunities to grow our business responsibly through economically attractive investments that contribute to our decarbonization goals, including achieving net zero by 2050, while also delivering commensurate returns and value for all stakeholders. In 2021, we reinforced our commitment to growing our renewable and battery storage portfolio to support the broader decarbonization of the U.S. economy, maintain the reliability and affordability of electricity, and enhance the long-term sustainability of Vistra.

In December, we published our Green Finance Framework, which enables us to issue green financial instruments to fund new or existing renewable and energy efficiency projects. We then successfully launched an attractively priced and upsized $1 billion of Green Perpetual Preferred

Stock—the first green preferred stock offering from a U.S. corporate issuer—to fund existing and new eligible green projects, including our renewable and battery storage development projects. Ultimately, this capital infusion will fund a portion of the development pipeline of several zero-carbon projects in our Vistra Zero portfolio in a cost-effective manner.

In connection with the Green Perpetual Preferred Stock offering, we announced our intention to grow Vistra Zero to at least 7,300 megawatts by 2026, with ~2,900 MW currently online (including our 2,300 MW low-cost nuclear facility, Comanche Peak). The $5 billion investment in Vistra Zero through 2026 is projected to contribute $450–$500 million of Adjusted EBITDA[1] annually by year-end 2026 (in addition to Adjusted EBITDA[1] generated by Comanche Peak). We intend to fund these development projects primarily through project financing, supplemented by Vistra Zero project cash flows and the net proceeds of the Green Perpetual Preferred Stock offering. Vistra's green and sustainable growth strategy through Vistra Zero is bolstered by our ability to use our existing sites, including repurposing retired or to-be-retired sites, which have existing access to transmission infrastructure.

Key development announcements and progress of our Vistra Zero projects in 2021 include:

In California:

- Moss Landing Energy Storage Facility continues to expand—Phases I (300 MW) and II (100 MW) both achieved commercial operations in 2021, and in February 2022, we announced further expansion through Phase III (350 MW), bringing the site's total energy storage capacity to 750 MW/3,000 MWh. We have the potential to eventually reach 1,500 MW, supporting the state of California's electricity needs. We experienced certain operational delays as the water-based heat suppression systems improperly leaked water on a small percentage of the battery modules, temporarily taking Phases I and II offline. However, we have identified the issues, are taking corrective actions, and expect to be storing and releasing energy to support California's grid during the all-important 2022 summer season.

In Illinois:

- A three-year effort culminated in the passage of an omnibus energy package that included our Illinois Coal to Solar & Energy Storage Initiative. As enacted, the legislation supports Vistra's future construction and operation of up to 300 MW of utility-scale solar and 150 MW of battery energy storage facilities at nine retired or to-be-retired coal plant sites across central and southern Illinois. The initiative will also include diverse suppliers while bringing a much-needed property tax base to local communities.

In Texas:

- Our Electric Reliability Council of Texas (ERCOT) 1,000 MW Phase I projects, announced in September 2020, took shape with three projects scheduled to achieve commercial operations prior to summer 2022:

  50 MW Brightside Solar Facility

  108 MW Emerald Grove Solar Facility

  260 MW DeCordova Energy Storage Facility

- We also grew the Vistra Zero portfolio in Texas by acquiring the to-be-constructed 110 MW Angus Solar Facility, expected online in 2023.

We believe Vistra is exactly the kind of company that should be embraced as a leader in the energy transition—our track record includes responsibly and justly retiring carbon-emitting resources, reclaiming sites, and investing in new green technology and resources. Since 2010, Vistra has retired more than 12,000 MW of coal and gas power plants, resulting in a 45% reduction of greenhouse gas (GHG) emissions through year-end 2020, compared to a 2010 baseline. Additionally, we have announced the expected retirement of nearly 8,000 MW of additional fossil-fueled power plants by 2027, for a total of ~20,000 MW since 2010, with plans to repurpose feasible sites to solar and energy storage developments. We are confident that our diversified asset mix will support the reliability of the electric system while providing customers with affordable energy that meets their sustainable preferences throughout the clean energy transition.

Vistra Zero carbon-free generation portfolio includes solar (Upton 2 Solar Facility, left), nuclear (Comanche Peak Power Plant, right), and battery storage (DeCordova Energy Storage Facility, below).

"We believe Vistra is exactly the kind of company that should be embraced as a leader in the energy transition."

Returning Significant Capital to Stockholders

Our long-term capital allocation plan reflects an anticipated return of capital of at least $7.5 billion to our common stockholders through year-end 2026. In October 2021, our board of directors approved a $2 billion share repurchase program, which we are on track to fully execute by year-end 2022. The share repurchase program is partially funded by the $1 billion of 8% preferred equity we issued in October 2021, and as announced on our fourth quarter 2021 earnings call, Vistra had repurchased ~$764 million of the $2 billion as of Feb. 22, 2022, resulting in a 7% reduction in shares outstanding since our previously reported share count as of Nov. 2, 2021. Once we conclude this initial $2 billion share repurchase plan, we then expect to allocate at least an average of $1 billion per year toward share repurchases from 2023 through 2026 for a total of at least $6 billion in five years. Vistra's core business is expected to generate on average $3+ billion per year of Adjusted EBITDA[1] and we expect to convert 60–70%+ of Adjusted EBITDA[1] to free cash flow, affording the significant cash flow to return to shareholders, especially since the Vistra Zero growth will be funded by internally generated Vistra Zero cash flow and third-party capital. Hence, our philosophy is simple and straight forward—for as long as we believe our stock is undervalued, we will dedicate significant cash flow from our core business to repurchase our shares.

Our capital allocation plan also reinforced our commitment to pay a meaningful and growing dividend. In October 2021, we announced our intent to allocate $300 million per year toward our common dividend. We anticipate this dividend policy will offer greater dividend yield growth for stockholders rather than identifying a target annual growth rate as we retire shares through our ongoing repurchases. This $300 million dividend pool will be spread over fewer shares, providing growth in dividend yield on the remaining shares. Our first quarter 2022 dividend of $0.17 per share of Vistra's common stock, represents a ~13% increase in the company's quarterly common stock dividend per share from its first quarter 2021 dividend.

Maintaining a Strong Balance Sheet

Vistra has always focused on a strong balance sheet, and it will remain a priority. A strong balance sheet provided the support we needed to withstand the hardships brought by Uri. Immediately following Uri, we executed financing transactions to support our liquidity needs, increasing our net debt by just over $2 billion. However, just a few months later, we announced as part of our capital allocation plan that we expect to further reduce corporate-level debt by ~$1.5 billion by year-end 2022 with plans to retire up to ~$3 billion of corporate-level debt in five years. By year-end 2021, we had already decreased corporate-level debt by ~$625 million and we believe we will approach pre-Uri debt levels by year-end 2022. We project that we will be able to maintain leverage in our current range of 3–3.5 times net debt to Adjusted EBITDA[1] in the near-term and reach the mid- to high-2s over the next five years, exclusive of the leverage to support the Vistra Zero growth.

Driving Long-Term, Sustainable Value Through Vistra's Integrated Business Model

Vistra's integrated model—a best-in-class generation fleet and premier retail business that we have grown and expanded over the past five years—provides the foundation and cash flow that support the three strategic priorities detailed above.

We have always believed in the value of our integrated operations, and we remain confident that the pairing of our low-cost, efficient, and diversified generation fleet—including our growing zero-carbon business—with our customer-centric retail platform and best-in-class commercial capabilities is the optimal way to maintain resiliency and create value for our stockholders. In fact, the uniquely low maintenance capital and operations and maintenance expense required to produce the $3 billion+ of Adjusted EBITDA[1] affords us a significant amount of free cash flow to support a diverse capital allocation plan with an emphasis on returning capital to financial stakeholders.

Financial Execution

We entered 2021 on the heels of an outstanding 2020 where we achieved results above the high end of our raised guidance range and marked the fifth year in a row that our financial results exceeded the midpoint of our Adjusted EBITDA from Ongoing Operations[1] guidance range. Uri led to a confluence of unpredictable events, exposing issues with the integrated natural gas and electric systems in the Texas ERCOT market, including impaired gas deliverability, challenging the financial strength we had worked hard to put in place. We faced the challenge and stabilized the company, and then immediately got back to work significantly offsetting the Uri financial impact and getting the company back on the path of exceptional performance and creating long-term shareholder value.

To mitigate the financial impact of Uri, we identified various self-help initiatives, including the monetization of certain commercial positions, optimizing spend on our generation O&M project work, retail cost savings and margin performance, and support group cost savings, culminating in value creation that exceeded our $500 million target. In addition, we have also been very active in the Texas 2021 legislative and ongoing regulatory deliberations regarding Uri, which, among other accomplishments, resulted in Vistra being allocated ~$544 million in ERCOT securitization payments. The self-help and securitization efforts resulted in an improvement following Uri of over $1 billion. These efforts also helped de-risk the integrated Texas natural gas and power systems reducing the potential volatility in the Texas ERCOT market and Vistra's financial and operating performance.

In the end, we reported 2021 Adjusted EBITDA from Ongoing Operations[1] of $1,941 million, including the impacts from Uri-related retail bill credit settlements resulting in high returns to Vistra. Excluding the $53 million related to these settlements, 2021 Adjusted EBITDA from Ongoing Operations[1] was $1,994 million, slightly favorable to the November revised and tightened midpoint of guidance. Under very difficult circumstances following Uri, we executed and accomplished exactly what we set out to do: stabilize the company and recover as much lost value as possible in order to put our company back on track to maximize our financial results for our stockholders.

Generation

During the week of Uri, our Texas generation fleet, which makes up 18% of the capacity available in ERCOT, provided between 25–30% of the power on the grid, far exceeding our market share. Unfortunately, the financial results did not match this performance due to the failures of the natural gas system and the uneven allocation of customer curtailments in ERCOT. Our employees went to extraordinary efforts, working around-the-clock in sub-freezing temperatures to keep our assets running and to maintain and restore power for the people of Texas. This was achieved while also effectively managing COVID-19 at all plant sites and constantly tracking and adjusting to CDC and OSHA recommendations. Vistra finished the year with commercial availability, a measure of the fleet's ability to meet demand during the highest margin hours, of ~92%—very strong performance for a fleet with the characteristics of ours.

In 2021, Vistra continued our operations performance improvement (OPI) initiative, realizing

Vistra's flagship retail brand, TXU Energy, launched a product specifically for electric vehicle owners, giving customers 50% off energy charges every weeknight and all weekend long—times when customers most often charge their vehicles.

$500 million of savings—a $275 million increase from the 2018 projection established with the Dynegy merger. OPI is now a part of our DNA with continuous idea generation and conversion of ideas to executable opportunities on a regular basis. Focused on learnings from Uri, we enhanced and further de-risked our fleet by investing more than $50 million in 2021, with execution beginning on another $30 million in 2022. These expenditures include the addition of onsite backup fuel at six plants with enough fuel for several days, additional offsite gas storage, and several actions to guard against severe weather impacts on critical equipment.

Our people are our most important asset, and their safety is our highest priority. Vistra's plants operated safely throughout the year—a testament to our "Best Defense" mindset which puts safety above all else. Through the team's efforts, Vistra ended the year without any serious injuries or fatalities to our Vistra employees or business partners working at our sites. Our focus on safety is further highlighted with 12 power plant sites achieving VPP Star status from OSHA, demonstrating superior efficacy of their safety and health management systems, and maintaining injury and illness rates below industry average. In 2021, we introduced the VPP process to five new facilities, and four of our power plants submitted VPP applications that are awaiting OSHA review.

Retail

Vistra's retail business rose to the challenge as well while maintaining our customer-centric approach despite the challenges of COVID-19 and Uri. During Uri, we assured customers they would be insulated from storm-related rate increases, donated $5 million to support our communities in need, and provided bill-pay assistance. By year end, Vistra's retail business grew ERCOT residential counts by ~23,000 customers, the highest organic growth we've seen since 2008. Most of this growth was within our flagship retail brand TXU Energy, demonstrating the strength of our brand promise and continued importance to our customers.

This was also a standout year for our two largest retail brands, with the launch of several first-to-market customer-centric products and others

> **Our people are our most important asset and their safety is our highest priority. Vistra's plants operated safely throughout the year—a testament to our "Best Defense" mindset which puts safety above all else.**

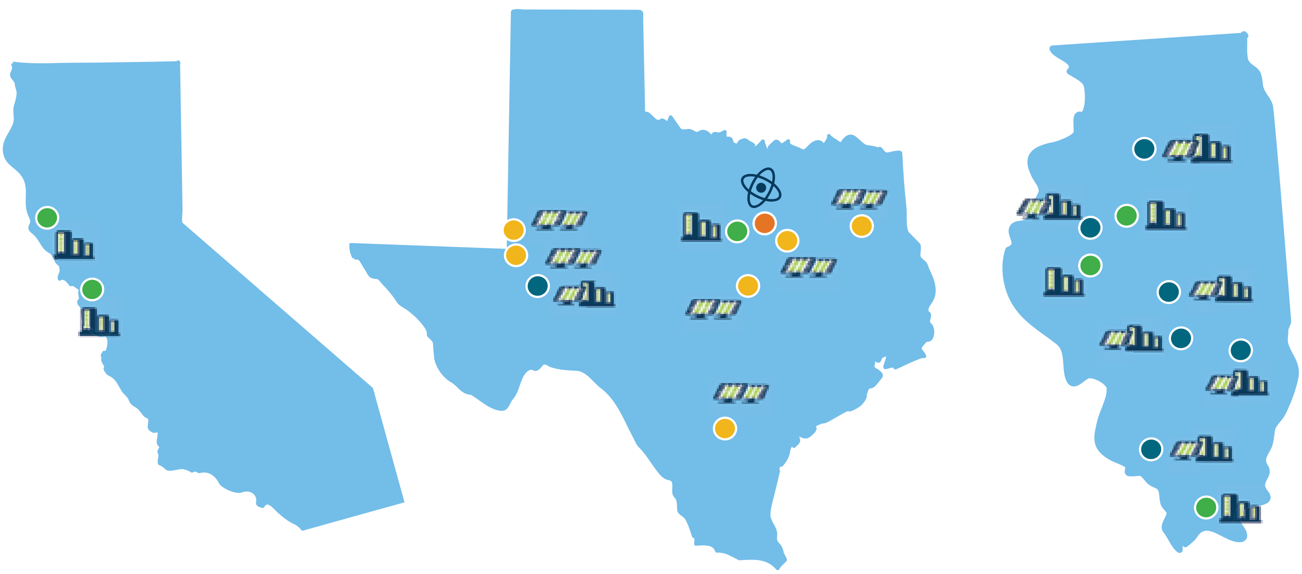
designed for increased use of electricity to fuel vehicles.

- Ambit's Winter Break plan gives customers in the Midwest and Northeast savings when they need it most by offering 50% off all winter long.
- Ambit Energy Bank gives Texas customers year-round control and predictability.
- TXU Energy continued to broaden its most imitated product portfolio with the launch of TXU Energy Freedom Rewards. This first-of-its-kind plan allows customers to earn 30% in free electricity for every dollar they spend on energy charges, automatically, all year long.
- TXU Energy EV Pass is designed specifically for electric vehicle owners.

Innovation remains a pillar of our retail business. As electric vehicle adoption takes off, we'll continue to develop products and partnerships to attract this important segment of customers. Additionally, we saw an increase in customers buying more than just electricity from us in 2021, growing our business of value-added products such as HVAC maintenance, home warranties, and surge protection plans. Vistra's approach to value-added services has been to partner with companies providing these services, earning a percentage of margin, rather than owning and competing in these businesses which have their own challenges and require their own sets of capabilities. This approach also allows us to be nimble and make changes while improving our offerings if the situation dictates. We believe this is the most cost-effective manner to broaden our product offering and protect our balance sheet and brands.

VISTRA ZERO

From the world's largest battery energy storage facility to miles and miles of solar panels, Vistra Zero is bringing a zero-carbon future to life.



SOLAR

Andrews Solar Facility
100 MW
Andrews County, TX

Angus Solar Facility
110 MW
Bosque County, TX

Brightside Solar Facility
50 MW
Live Oak County, TX

Emerald Grove Solar Facility
108 MW
Crane County, TX

Forest Grove Solar Facility
200 MW
Henderson County, TX

Oak Hill Solar Facility
200 MW
Rusk County, TX

NUCLEAR

Comanche Peak Nuclear Power Plant
2,300 MW
Somervell County, TX

ENERGY STORAGE

DeCordova Energy Storage Facility
260 MW
Hood County, TX

Edwards Energy Storage Facility
37 MW
Peoria County, IL

Havana Energy Storage Facility
37 MW
Mason County, IL

Joppa Energy Storage Facility
37 MW
Massac County, IL

Moss Landing Energy Storage Facility
750 MW/3,000MWh
Moss Landing, CA

Oakland Energy Storage Facility
43.25 MW
Oakland, CA

SOLAR + ENERGY STORAGE

Baldwin Solar & Energy Storage Facility
68 MW solar; 9 MW battery
Randolph County, IL

Coffeen Solar & Energy Storage Facility
44 MW solar; 6 MW battery
Montgomery County, IL

Duck Creek Solar & Energy Storage Facility
20 MW solar; 3 MW battery
Fulton County, IL

Hennepin Solar & Energy Storage Facility
50 MW solar; 6 MW battery
Putnam County, IL

Kincaid Solar & Energy Storage Facility
60 MW solar; MW battery
Christian County, IL

Newton Solar & Energy Storage Facility
52 MW solar; 7 MW battery
Jasper County, IL

Upton 2 Solar & Energy Storage Facility
180 MW solar; 10 MW/42 MWh battery
Upton County, TX

List includes publicly announced projects under development

ESG Accomplishments

Before I close, while our business portfolio transformation is a key element of our sustainability strategy, I would be remiss if I did not highlight other ESG accomplishments we achieved this year:

- Named one of America's Most JUST Companies, by JUST Capital and its media partner CNBC, for a commitment to serving workers, customers, communities, the environment, and stockholders.
- Honored with 2021 Texan by Nature 20 designation by the conservation non-profit Texan by Nature for a demonstrative commitment to conservation and sustainability.
- Received the 2021 Excellence in Surface Coal Mining Reclamation Award from the Office of Surface Mining Reclamation & Enforcement, a bureau of the U.S. Department of the Interior, for work done to reclaim and restore previously mined land at Monticello-Winfield Mine. The award recognizes companies that achieve the most exemplary coal mine reclamation in the nation.
- Joined Disability:IN, the leading non-profit resource for business disability inclusion world-wide, reinforcing commitment to equality and inclusion at Vistra.
- Continued year two of a five-year, $10 million commitment to support organizations that grow minority-owned small businesses, enhance economic development, and provide educational opportunities for students from diverse backgrounds.
- Advanced diversity, equity, and inclusion (DEI) in the workplace through strengthening internal hiring and recruiting practices through numerous initiatives including training for hiring managers and partnerships with minority-serving institutions.
- Incorporated an ESG Index, with a 10% weighting, into Vistra's compensation scorecard, ensuring accountability all the way to the top of the company.

Conclusion

We continue to believe that the most effective and sustainable companies have a well-balanced focus on a variety of stakeholders including you—our investors—and our customers, communities, people, and suppliers. We are supplying a vital product to society, and we must balance that crucial role with our environmental footprint. In 2021, we advanced our company in many important ways, especially in the areas represented by ESG. Although we endured an unprecedented weather event that resulted in a significant financial impact and a temporary loss of value, we finished the year strong, fully recovering the loss in value of our stock from Uri by year end. Ultimately, I am most proud of how this company responded to the impacts from Uri, most of which were uncontrollable, and continued to live our core principles of doing business the right way, competing as a team to win, and caring for all of our stakeholders. We never wavered and we did not give up, and we are now back on track with our stock price continuing to respond favorably to our new and improved capital allocation plan. We cannot change what happened during Uri, but we can and did learn from it, de-risking and strengthening our company for the future. We completed 2021 with a clear strategic direction as a leader in the clean energy transition coupled with a capital allocation plan that we believe will provide exceptional value to our stockholders for years to come.

We begin 2022 from a position of strength for which we can all be proud. It was with this strength in mind that on March 21, 2022, I announced that I will be transitioning the role of CEO to my colleague, Jim Burke. Leading Vistra has been the most rewarding experience of my 40-year career. I remain excited about the long-term opportunity ahead as Vistra returns significant capital to investors while transitioning our fleet to lower carbon resources. Jim is a proven leader who possesses deep experience in our company and industry and understands the company's commitment to all our stakeholders. I'm excited to watch him lead Vistra to continued success.

Thank you for your interest in Vistra—as always, we look forward to its future!

Curt Morgan
Chief Executive Officer

[1] Adjusted EBITDA is a non-GAAP financial measure. Please refer to the "Non-GAAP Reconciliation" table on page 8 of this Annual Report.

Non-GAAP Financial Measures and Forward-Looking Statements

This letter includes references to Adjusted EBITDA which is a non-GAAP financial measure. For reconciliations between our non-GAAP measures and the nearest GAAP measures, please refer to the table below. 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'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'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 Reconciliation — 2021 Adjusted EBITDA

Year Ended December 31, 2021 (Unaudited) (Millions of Dollars)

	Retail	Texas	East	West	Sunset	Eliminations/ Corp and Other	Ongoing Operations Consolidated	Asset Closure	Vistra Consolidated
Net income (loss)	**2,196**	**(2,512)**	**(567)**	**1**	**(413)**	**53**	**(1,242)**	**(22)**	**(1,264)**
Income tax expense (benefit)	2	—	—	—	—	(460)	(458)	—	(458)
Interest expense and related charges (a)	9	(14)	15	(9)	2	380	383	1	384
Depreciation and amortization (b)	212	686	698	60	139	36	1,831	—	1,831
EBITDA before Adjustments	**2,419**	**(1,840)**	**146**	**52**	**(272)**	**9**	**514**	**(21)**	**493**
Unrealized net (gain)/loss resulting from hedging transactions	(1,403)	1,139	655	38	330	—	759	—	759
Generation plant retirement expenses	—	—	—	—	18	—	18	—	18
Fresh start / purchase accounting impacts	2	(14)	(74)	—	(52)	—	(138)	—	(138)
Impacts of Tax Receivable Agreement	—	—	—	—	—	(53)	(53)	—	(53)
Non-cash compensation expenses	—	—	—	—	—	51	51	—	51
Transition and merger expenses	(2)	—	—	—	—	9	7	(15)	(8)
Other, including impairment of long-lived and other assets	57	18	9	3	33	(43)	77	3	80
COVID-19-related expenses (c)	—	4	1	—	2	1	8	—	8
Winter Storm Uri impacts (d)	239	457	—	—	1	1	698	—	698
Adjusted EBITDA	**1,312**	**(236)**	**737**	**93**	**60**	**(25)**	**1,941**	**(33)**	**1,908**

(a) Includes $134 million of unrealized mark-to-market net gains on interest rate swaps.

(b) Includes nuclear fuel amortization of $78 million in the Texas segment.

(c) Includes material and supplies and other incremental costs related to our COVID-19 response.

(d) Includes the following of the Winter Storm Uri impacts, which we believe are not reflective of our operating performance: allocation of ERCOT default uplift charges which are expected to be paid over more than 90 years under current protocols; accrual of Koch earn-out amounts that the Company will pay by the end of the second quarter of 2022; future bill credits related to Winter Storm Uri (as further described below); and Winter Storm Uri related legal fees and other costs. The adjustment for future bill credits relates to large commercial and industrial customers that curtailed their usage during Winter Storm Uri and will reverse and impact Adjusted EBITDA in future periods as the credits are applied to customer bills. We estimate the amounts to be applied in future periods are 2022 (approximately $150 million), 2023 (approximately $67 million), 2024 (approximately $11 million) and 2025 (approximately $4 million). The Company believes the inclusion of the bill credits as a reduction to Adjusted EBITDA in the years in which such bill credits are applied more accurately reflects its operating performance.

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, 2021

— 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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 30, 2021, the aggregate market value of the Vistra Corp. common stock held by non-affiliates of the registrant was $8,921,038,713 based on the closing sale price as reported on the New York Stock Exchange.

As of February 22, 2022, there were 448,803,986 shares of common stock, par value $0.01, outstanding of Vistra Corp.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant's 2022 annual meeting of stockholders are incorporated in Part III of this annual report on Form 10-K.

TABLE OF CONTENTS

		PAGE
Glossary		ii
	PART I.	
Item 1.	**BUSINESS**	1
Item 1A.	**RISK FACTORS**	19
Item 1B.	**UNRESOLVED STAFF COMMENTS**	46
Item 2.	**PROPERTIES**	46
Item 3.	**LEGAL PROCEEDINGS**	48
Item 4.	**MINE SAFETY DISCLOSURES**	48
	PART II.	
Item 5.	**MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES**	49
Item 6.	**[RESERVED]**	50
Item 7.	**MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**	50
Item 7A.	**QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**	80
Item 8.	**FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**	86
Item 9.	**CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**	164
Item 9A.	**CONTROLS AND PROCEDURES**	164
Item 9B.	**OTHER INFORMATION**	166
Item 9C.	**DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTION**	166
	PART III.	
Item 10.	**DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**	167
Item 11.	**EXECUTIVE COMPENSATION**	167
Item 12.	**SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**	167
Item 13.	**CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE**	167
Item 14.	**PRINCIPAL ACCOUNTANT FEES AND SERVICES**	167
	PART IV.	
Item 15.	**EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**	168
Item 16.	**FORM 10-K SUMMARY**	183
Signatures		184

Vistra Corp.'s (Vistra) annual reports, quarterly reports, current reports and any amendments to those reports are made available to the public, free of charge, on the Vistra website at *http://www.vistracorp.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 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's website. The information on Vistra'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 and its subsidiaries occasionally make references to Vistra (or "we," "our," "us" or "the Company"), Luminant, TXU Energy, Ambit, Value Based Brands, 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 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.

2020 Form 10-K	Vistra's annual report on Form 10-K for the year ended December 31, 2020, filed with the SEC on February 26, 2021
Ambit or Ambit Energy	Ambit Holdings, LLC, and/or its subsidiaries (d/b/a Ambit), depending on context
ARO	asset retirement and mining reclamation obligation
CAA	Clean Air Act
CAISO	The California Independent System Operator
CARES Act	Coronavirus Aid, Relief, and Economic Security Act
CCGT	combined cycle gas turbine
CCR	coal combustion residuals
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 Oncor Electric Delivery Holdings Company LLC and its direct and indirect subsidiaries (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 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 (each d/b/a Dynegy, Better Buy Energy, Brighten Energy, Honor Energy and True Fit Energy), indirect, wholly owned subsidiaries of Vistra, 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, on the Effective Date
ESG	environmental, social and governance
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc.
ESS	energy storage system
Exchange Act	Securities Exchange Act of 1934, as amended
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, a REP in certain areas of MISO that is engaged in the retail sale of electricity to municipal customers

ICE	Intercontinental Exchange
IEPA	Illinois Environmental Protection Agency
IPCB	Illinois Pollution Control Board
IRC	Internal Revenue Code of 1986, as amended
IRS	U.S. Internal Revenue Service
ISO	independent system operator
ISO-NE	ISO New England Inc.
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 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, with Vistra as the surviving corporation
Merger Agreement	the Agreement and Plan of Merger, dated as of October 29, 2017, by and between Vistra and Dynegy
Merger Date	April 9, 2018, the date Vistra 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
NELP	Northeast Energy, LP, a joint venture between Dynegy Northeast Generation GP, Inc. and Dynegy Northeast Associates LP, Inc., both indirect subsidiaries of Vistra, and certain subsidiaries of NextEra Energy, Inc. Prior to the NELP Transaction, NELP indirectly owned Bellingham NEA facility and the Sayreville facility.
NELP Transaction	a transaction among Dynegy Northeast Generation GP, Inc., Dynegy Northeast Associates LP, Inc. and certain subsidiaries of NextEra Energy, Inc. wherein the indirect subsidiaries of Vistra redeemed their ownership interest in NELP partnership in exchange for 100% ownership interest in NJEA, the entity which owns the Sayreville facility
NERC	North American Electric Reliability Corporation
NJEA	North Jersey Energy Associates, A Limited Partnership
NO_X	nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NYISO	New York Independent System Operator, Inc.
NYMEX	the New York Mercantile Exchange, a commodity derivatives exchange
NYSE	New York Stock Exchange
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
OPEB	postretirement employee benefits other than pensions
Parent	Vistra 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
Preferred Stock	Vistra's Series A Preferred Stock and Series B Preferred Stock
Public Power	Public Power, LLC (d/b/a Public Power), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO 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, and has jurisdiction over oil and natural gas exploration and production, permitting and inspecting intrastate pipelines, and overseeing natural gas utility rates and compliance
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
Series A Preferred Stock	Vistra's 8.0% Series A Fixed Rate Reset Cumulative Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
Series B Preferred Stock	Vistra's 7.0% Series B Fixed Rate Reset Cumulative Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
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 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
TriEagle Energy	TriEagle Energy, LP (d/b/a TriEagle Energy, TriEagle Energy Services, Eagle Energy, Energy Rewards, Power House Energy and Viridian Energy), an indirect, wholly owned subsidiary of Vistra, 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
TXU Energy	TXU Energy Retail Company LLC (d/b/a TXU), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers

U.S.	United States of America
U.S. Gas & Electric	U.S. Gas and Electric, Inc. (d/b/a USG&E, Illinois Gas & Electric and ILG&E), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO 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, Express Energy and Veteran Energy), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
Vistra	Vistra 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. Effective July 2, 2020, Vistra Energy Corp. changed its name to Vistra Corp.
Vistra Intermediate	Vistra Intermediate Company LLC, a direct, wholly owned subsidiary of Vistra
Vistra Operations	Vistra Operations Company LLC, an indirect, wholly owned subsidiary of Vistra 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 senior secured financing facilities (see Note 11 to the Financial Statements)
Vistra Zero	Vistra Zero LLC

[THIS PAGE INTENTIONALLY LEFT BLANK]

PART I

Item 1. BUSINESS

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

Business

Vistra is a holding company operating an integrated retail and electric power 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 law in 2016. Effective July 2, 2020, we changed our name from Vistra Energy Corp. to Vistra Corp. to distinguish from companies that are involved in exploring for, producing, refining, or transporting fossil fuels (many of which use "energy" in their names) and to better reflect our integrated business model, which combines a retail electricity and natural gas business focused on serving its customers with new and innovative products and services and an electric power generation business leading the clean power transition through our Vistra Zero portfolio while powering the communities we serve with safe, reliable and affordable power.

We serve approximately 4.3 million customers and operate in 20 states and the District of Columbia. Our generation fleet totals approximately 38,700 MW of generation capacity with a portfolio of natural gas, nuclear, coal, solar and battery energy storage facilities.

Vistra has six reportable segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. See *Market Discussion* below and Note 20 to the Financial Statements for further information concerning our reportable segments, including an update of our reportable segments in the third quarter of 2020.

Business Strategy

Vistra is a leader in the clean power transition. With a strong zero-carbon generation portfolio and a deliberate and responsible strategy to decarbonize, the company is focused on delivering healthy returns and value for all stakeholders. Our business strategy is focused on the following areas:

- *Growth and transformation.* Vistra's strategy is to responsibly and reliably grow our business through economically attractive investments in retail, renewable, and energy storage assets that assist in reducing our carbon footprint and create a more sustainable and resilient company well positioned to generate stable long-term value for all of our stakeholders. Since 2010, Vistra has retired more than 12,000 MW of coal and gas power plants resulting in a 45% reduction of greenhouse gas (GHG emissions), a 45% reduction in carbon dioxide (CO_2) emissions, a 55% reduction in nitrogen oxide (NO_X) emissions, and a 75% reduction in sulfur dioxide (SO_2) emissions through year-end 2020, compared to a 2010 baseline. Now, we are transforming our generation portfolio through investments in zero-carbon resources and new carbon-reducing technologies, targeting net-zero carbon emissions by 2050. By year-end 2026, our Vistra Zero portfolio is expected to grow to 7,300 MW of zero-carbon generation, including solar, energy storage and our Comanche Peak nuclear power plant. Additionally, we have announced the retirement of approximately 7,500 MW of coal-fueled power plants by 2027, with plans to repurpose feasible sites to solar and energy storage developments. Repurposed sites provide a strategic advantage in the development of greener power due to the interconnection infrastructure already available, but additionally, and importantly, they allow us to continue supporting the local communities and our employees in those areas. We believe our diversified asset mix will support the reliability of the electric system while providing customers with cost-effective energy that meets their sustainable preferences throughout the clean power transition. 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. To advance our sustainability and energy transition initiatives, in December 2021, we adopted our Green Finance Framework, pursuant to which we issued $1.0 billion of Series B Preferred Stock to finance or refinance, in whole or in part, new or existing eligible green projects. We intend to opportunistically evaluate the acquisition and development of high-quality generation and storage assets and power-related businesses, including renewable energy and battery storage assets as well as retail businesses, that complement our core capabilities and align with our operational, financial and sustainability goals. We pride ourselves on our deliberate and responsible approach to grow and transform, considering impacts on all stakeholders. We make disciplined investments that are consistent with our focus on maintaining both a strong balance sheet and strong liquidity profile and our commitment to ensuring grid reliability, affordable power, and pursuit of a just transition away from carbon-emitting generation assets for the communities in which we operate and serve. As a result, consistent with our disciplined capital allocation approval process, the growth opportunities we pursue must have compelling economic value and align with or enhance our purpose and core principles.

- *Disciplined capital allocation.* Vistra takes a disciplined approach to capital allocation in support of our commitment to maintain a strong balance sheet. We thoughtfully make capital allocation decisions that we believe will lead to attractive cash returns on investment, including returning capital to our stockholders through quarterly dividends and our share repurchase program as reflected in our current plans to return up to $7.5 billion in capital to common shareholders and reduce up to $3 billion in debt (exclusive of potential limited recourse project financing) through 2026. In addition to our dedicated approach to returning value to all stakeholders, we invest prudently in the maintenance of our existing assets and potential growth acquisitions. A strong balance sheet ensures Vistra's interest expense is manageable in a variety of wholesale power price environments while giving Vistra access to flexible and diverse sources of liquidity needed to make prudent capital investment decisions. We believe in cost discipline and strong commercial management of our assets and commodity positions to deliver long-term value to our stakeholders, to maintain the safety and reliability of our facilities, all while accelerating growth in our Vistra Zero portfolio pipeline with cost-efficient capital and investment in new technologies when economic, including solar assets and energy storage systems, resulting in a continued modernization of Vistra's generation fleet.

- *Integrated business model.* Our integrated business model is an important component of our business strategy. This element of our business provides long-term sustainable solutions enabled by our diversified portfolio. This key factor distinguishes us from our electricity competitors by pairing our reliable and efficient mining, diversified generation fleet and wholesale commodity risk management capabilities with our retail platform. Coupling retail with generation is a core competitive advantage that reduces the effects of commodity price movements and contributes to stable earnings and predictable cash flow, a crucial feature of the strategy as Vistra responsibly grows its renewables portfolio and winds down its carbon-emitting assets.

- *Superior customer service.* Through our retail brands, including TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. 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 safe, reliable and affordable 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 solutions from our competitors. We strive to be at the forefront of innovation with new environmentally-conscious and sustainable-focused product offerings and customer experiences to reinforce our value proposition. We maintain a focus on solutions that provide our customers with choice, convenience and control over how and when they use electricity and related services, including TXU Energy's Free Nights and Solar Days residential plans, MyEnergy Dashboard^{SM}, TXU Energy's iThermostat product and mobile solution, the TXU Energy Rewards program, the TXU Energy Green Up^{SM} renewable energy credit program and a diverse set of solar options. Our focus on superior customer service guides our efforts in acquiring new residential and commercial customers, serving and retaining existing customers, and maintaining valuable sales channels for our electricity generation resources. We believe our dependable customer service, innovative 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 delivering long-term stakeholder value is increased as a result 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 as we lead in the clean power transition through the acceleration of our renewables portfolio. 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 and is instrumental in our long-term value proposition.

- *Integrated hedging and commercial management.* Our commercial team is focused on effectively and efficiently managing risk, through opportunistic hedging, and optimizing our assets and business positions. We proactively manage our exposure to wholesale electricity prices and fuel costs 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 actively hedge near-term cash flows 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 attractive liquidity profile, will provide long-term advantages through cycles of higher and lower commodity prices.

- *Corporate responsibility and ESG initiatives.* It is our purpose to light up people's lives and power a better way forward. We strive to be a good corporate citizen by investing in our employees, putting customers and suppliers first, and improving communities where we live, work and serve as we accelerate toward a clean energy future. Vistra and its employees are actively engaged in programs intended to support our customers 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. Beyond these giving initiatives, Vistra embeds ESG and considers all stakeholders – customers, suppliers, local communities, employees, contractors, investors and the environment, among others – into all of our decisions, processes and activities. The Board has ultimate oversight of all our ESG initiatives and ensures these considerations are embedded at every level of our company. We know that prioritizing our stakeholders leads to higher customer satisfaction, more community involvement and support, and committed employees and suppliers, which in turn, leads to a more sustainable company. Our ESG initiatives complement our business strategy and strengthen our resiliency. For instance, our investment in and growth of Vistra Zero supports our long-term goal to achieve net-zero carbon emissions by 2050. We stay informed of evolving ESG standards and remain committed to provide specific and measurable ESG goals and initiatives in a transparent manner.

Recent Developments

Dividend Declarations — In February 2022, the Board declared a quarterly dividend of $0.17 per share of common stock that will be paid in March 2022 and a semi-annual dividend of $40.00 per share of Series A Preferred Stock that will be paid in April 2022.

Green Finance Framework — In December 2021, we announced the publication of our Green Finance Framework, which allows us to issue green financial instruments to fund new or existing projects that support renewable energy and energy efficiency with alignment to our ESG initiatives. See below and Note 14 to the Financial Statements for more information concerning the Series B Preferred Stock, which was issued in December 2021 under the Green Finance Framework.

Series A Preferred Stock Offering — On October 15, 2021, we issued 1,000,000 shares of Series A Preferred Stock in a private offering (Series A Offering). The net proceeds of the Series A Offering were approximately $990 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Series A Offering to repurchase shares of our outstanding common stock under the Share Repurchase Program. See Note 14 to the Financial Statements for more information concerning the Series A Preferred Stock and our Share Repurchase Program.

Series B Preferred Stock Offering — On December 10, 2021, we issued 1,000,000 shares of Series B Preferred Stock in a private offering (Series B Offering) under our Green Finance Framework. The net proceeds of the Series B Offering were approximately $985 million, after deducting underwriting commissions and offering expenses. We intend to use the proceeds from the Series B Offering to pay for or reimburse existing and new eligible renewable and battery ESS developments. See Note 14 to the Financial Statements for more information concerning the Series B Preferred Stock.

Commodity-Linked Revolving Credit Facility — On February 4, 2022, Vistra Operations entered into a credit agreement by and among Vistra Operations, Vistra Intermediate, the lenders, joint lead arrangers and joint bookrunners party thereto, and Citibank, N.A., as administrative agent and collateral agent. The Credit Agreement provides for a $1.0 billion senior secured commodity-linked revolving credit facility (the Commodity-Linked Facility). Vistra Operations intends to use the liquidity provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes. See Note 11 to the Financial Statements for more information concerning the Commodity-Linked Facility.

Market Discussion

The operations of Vistra are aligned into six reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. The following is a summary of our segments:

- The Retail segment represents Vistra's retail sales of electricity and natural gas to residential, commercial and industrial customers.
- The Texas segment represents Vistra's electricity generation operations in ERCOT, other than assets that are now part of the Sunset or Asset Closure segments, respectively.
- The East segment represents Vistra's electricity generation operations in the Eastern Interconnection of the U.S. electric grid, other than assets that are now part of the Sunset or Asset Closure segments, respectively, and includes operations in PJM, ISO-NE and NYISO.
- The West segment represents Vistra's electricity generation operations in CAISO. As reflected by the Moss Landing and Oakland ESS projects (see Note 3 to the Financial Statements), the Company expects to expand its operations in the West segment.
- The Sunset segment represents plants with announced retirement plans that were previously reported in the ERCOT, PJM and MISO segments. Given recent and expected future retirements of certain power plants, management believes it is important to have a segment which differentiates between operating plants with defined retirement plans and operating plants without defined retirement plans.
- The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines.

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

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

Separately, ISOs/RTOs 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. ISOs/RTOs administer energy and ancillary service markets in the short term, which usually consists of day-ahead and real-time markets. Several ISOs/RTOs also ensure long-term planning reserves through monthly, semiannual, annual and multi-year capacity markets. The ISOs/RTOs 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 ISOs/RTOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and ISOs/RTOs, their respective roles and responsibilities do not generally overlap.

In ISO/RTO regions with centrally dispatched market structures (e.g., ERCOT, PJM, ISO-NE, NYISO, MISO, and CAISO), 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 ISO/RTO may produce different prices respective to other zones within the same ISO/RTO 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. Generators will receive the location-based marginal price for their output.

Retail Markets

The Retail segment is engaged in retail sales of electricity, natural gas and related services to approximately 4.3 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 U.S. 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 2.4 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 and excellent customer service. As of December 31, 2021, we provided electricity to approximately 30% of the residential customers in ERCOT and for approximately 15% 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 help 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, U.S. Gas & Electric and Ambit Energy retail businesses, through which we provide retail electricity, natural gas and related services to approximately 1.9 million customers in 18 states and the District of Columbia.

Texas Segment

Our Texas segment is comprised of 18 power generation facilities totaling 17,623 MW of generation capacity in ERCOT. We also operate a 10 MW battery ESS at our Upton 2 solar facility.

ISO/RTO	Technology	Primary Fuel	Number of Facilities	Net Capacity (MW)
ERCOT	CCGT	Natural Gas	7	7,838
ERCOT	ST	Coal	2	3,850
ERCOT	CT or ST	Natural Gas	7	3,455
ERCOT	Nuclear	Nuclear	1	2,300
ERCOT	Solar/Battery	Renewable	1	180
		Total Texas Segment	18	17,623

We plan to develop up to 768 MW of solar photovoltaic power generation facilities and 260 MW of battery ESS in Texas with estimated commercial operation dates between first quarter of 2022 to fourth quarter of 2023. See Note 3 to the Financial Statements for a summary of our solar and battery energy storage projects.

ERCOT — ERCOT is an ISO that manages the flow of electricity from approximately 86,000 MW of summer peak 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. In 2014, 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. The slope of the ORDC curve is determined through a mathematical loss of load probability calculation using forecasted reserves and historical data. In both March 2019 and March 2020, ERCOT implemented 0.25 standard deviation shifts in the loss of load probability calculation and moved to using a single blended ORDC curve; these changes resulted in a more rapid escalation in power prices as operating reserves fall below defined thresholds. Effective January 1, 2022, when operating reserves drop to 3,000 MW or less, the ORDC automatically adjusts power prices to the established value of lost load (VOLL), which is set at $5,000/MWh which is equal to the high system-wide offer cap. ERCOT also calculates the "peaker net margin" based on revenues a hypothetical unhedged peaking unit would collect in the market. If the peaker net margin exceeds a certain threshold, the system-wide offer cap is reduced to the low system-wide offer cap of $2,000/MWh for the remainder of the calendar year. The peaker net margin exceeded the threshold for the first time during Winter Storm Uri, and as a result the low system-wide offer cap was in place for the balance of 2021. Historically, high demand due to elevated temperatures in the summer months or high demand due to reduced temperatures in the winter months, combined with underperformance of wind generation, has created the conditions during which the ORDC contributes meaningfully to power prices. Extreme weather conditions can also lead to scarcity conditions regardless of season. Other than during periods of "scarcity pricing," the price of power is typically set by natural gas-fueled generation facilities (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, financial 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 physical market in which electricity is dispatched and priced 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, responsive reserve service and non-spinning reserve service. Ancillary services are provided by generators to help maintain the stable voltage and frequency requirements of the transmission system. Because ERCOT has one of the highest concentrations of wind and solar capacity generation among U.S. markets, the ERCOT market is more susceptible to fluctuations in wholesale electricity supply due to intermittent wind and solar production, making ERCOT more vulnerable to periods of generation scarcity. Beginning in July 2021, ERCOT has increased its ancillary service procurement volumes to maintain a more conservative level of operating reserves.

East Segment

Our East segment is comprised of 21 power generation facilities in 10 states totaling 12,093 MW of generating capacity in PJM, ISO-NE and NYISO.

ISO/RTO	Technology	Primary Fuel	Number of Facilities	Net Capacity (MW)
PJM	CCGT	Natural Gas	8	6,081
PJM	CT	Natural Gas	4	1,346
PJM	CT	Fuel Oil	2	93
ISO-NE	CCGT	Natural Gas	6	3,361
NYISO	CCGT	Natural Gas	1	1,212
		Total East Segment	21	12,093

We plan to develop up to 300 MW of solar photovoltaic power generation facilities and up to 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois with estimated commercial operation dates for these facilities ranging from 2023 to 2025. See Note 3 to the Financial Statements for a summary of our solar and battery energy storage projects.

PJM — PJM is an RTO that manages the flow of electricity from approximately 180,000 MW of generation capacity to approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Like ERCOT, 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. 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 a long-term market for capacity. We have participated in RPM auctions for years up to and including PJM's planning year 2022-2023, which ends May 31, 2023. Due to a FERC order issued in December 2021, PJM's RPM auction for planning year 2023-2024 will be delayed and is expected to be run in the summer of 2022. We also enter into bilateral capacity transactions. PJM's Capacity Performance (CP) rules were designed to improve system reliability and include penalties for under-performing units and reward for over-performing units during shortage events. Full transition of the capacity market to CP rules occurred in 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.

ISO-NE — 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. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. 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.

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

NYISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. 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.

West Segment

Our West segment is comprised of two power generation facilities totaling 1,130 MW of generation capacity and the first two phases of a battery ESS facility totaling 400 MW in CAISO, all of which are located in California.

ISO/RTO	Technology	Primary Fuel	Number of Facilities	Net Capacity (MW)
CAISO	CCGT	Natural Gas	1	1,020
CAISO	Battery	Renewable	1	400
CAISO	CT	Fuel Oil	1	110
		Total West Segment	3	1,530

We plan to develop an additional 350 MW in the third phase of our battery ESS at our Moss Landing Power Plant site with an estimated commercial operation date in the summer of 2023.

CAISO — 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 in CAISO utilizing an LMP methodology. 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.

Sunset Segment

Our Sunset segment is comprised of 10 power generation facilities totaling 7,486 MW of generating capacity in MISO, PJM and ERCOT. The Sunset segment represents plants with announced retirement plans between 2022 and 2027 that were previously reported in the ERCOT, PJM and MISO segments. See Note 4 to the Financial Statements for more information related to these planned generation retirements.

ISO/RTO	Technology	Primary Fuel	Number of Facilities	Net Capacity (MW)
ERCOT	ST	Coal	1	650
MISO	ST	Coal	4	3,187
MISO	CT	Natural Gas	2	221
PJM	ST	Coal	3	3,428
		Total Sunset Segment	10	7,486

See *Texas Segment* above for a discussion of the ERCOT ISO and *East Segment* above for a discussion of the PJM RTO.

MISO — MISO is an RTO that manages the flow of electricity from approximately 202,000 MW of 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.

MISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the regional zones in MISO and are largely influenced by transmission constraints and fuel supply. 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 Planning Resource 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.

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 ISO/RTO 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 are impacted by extreme or sustained weather conditions and 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 have made, and may make such fluctuations more pronounced. 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 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 19 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 U.S. Gas & Electric through the Ambit Transaction, Crius Transaction and the Merger, as the case may be. As of December 31, 2021, we have reflected intangible assets on our balance sheet for our trade names of approximately $1.341 billion (see Note 6 to the Financial Statements).

Human Capital Resources

As a key component of our core principle that *we work as a team*, Vistra believes our most valuable asset is our talented, dedicated and diverse group of employees who work together to achieve our objectives, and our top priority is ensuring their safety. One of Vistra's core principles is that *we care about our key stakeholders*, including our employees. We invest in our people through numerous development and training opportunities, engaging employee programs and generous benefit and wellness offerings.

As of December 31, 2021, we had approximately 5,060 full-time employees, including approximately 1,400 employees under collective bargaining agreements.

Safety

Vistra's mindset around safety is exemplified by our motto: *Best Defense. Everyone wins. No one gets hurt.* Our safety culture revolves around people and human performance. We place a high importance on continuous improvement, along with a keen focus on numerous learning and error-prevention tools. To facilitate a learning environment, our various operating plants share their investigations and learnings of all safety events with all operations employees on weekly calls. The information is presented by front-line employees and supported by management. The lessons from each event are shared across the fleet to prevent similar incidents at other locations. All personnel at Vistra locations are encouraged to be actively involved in the safety process. Managers are required to participate in safety engagements with staff to enable constant communication and sustained interaction. In 2021, the generation fleet conducted more than 57,000 leadership safety engagements across the fleet continuing our employee driven safety program focused on engagement of all employees.

Our focus on reducing the severity of injuries for both our employees and contractors who work with us has shown positive results. In 2021, we did not have any serious injuries, as determined in accordance with industry standards, or fatalities to our Vistra employees or business partners working at our sites. Although we do not focus on recordable incidents, our Total Recordable Incident rate (TRIR) for the company was 0.87, better than the second quartile as compared to the Edison Electric Institute (EEI) 2020 Total Company Injury Data. We encourage near-miss reporting and review of events to promote a learning environment. In 2021, safety learning calls were held every week where near-miss and safety events were reviewed by our operating teams to promote learning across the fleet.

All Vistra employees are covered by our safety program. Corporate and retail employees are required to complete periodic training on safety topics through our online learning management system. Employees who are located at a power plant are required to complete trainings based on job function, which is also tracked through our central learning management system. In addition, the Company engages an independent third-party conformity assessment and certification vendor to manage adherence to our safety standards for all vendors and contractors who work at our plants. In addition, we work closely with our suppliers and contractors to ensure our safety practices are upheld.

All of our power plant facilities have effective health and safety programs and comply with OSHA regulations. In addition to compliance, our generation fleet has a total of 12 plants that have been awarded the Voluntary Protection Program (VPP) Star designation by the OSHA for superior demonstration of effective safety and health management systems and for maintaining injury and illness rates below the national averages for our industry. Four additional plants have submitted applications and are awaiting review by the OSHA. VPP Star status is the highest designation of OSHA's Voluntary Protection Programs. The achievement recognizes employers and workers who have implemented effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics averages for their respective industries. These sites are self-sufficient in their ability to control workplace hazards and are reevaluated every three to five years. Additionally, 31 of our power plants and mine locations have adopted a proactive Behavior Based Safety approach to safety which focuses on identifying and providing feedback on at-risk behaviors observed.

In 2021, we continued our COVID-19 protections and protocols ensuring the safety of all of our employees.

Diversity, Equity and Inclusion

We recognize the value of having a diverse and inclusive workforce. Our diversity includes all the ways we differ, such as age, gender, ethnicity and physical appearance, as well as underlying differences such as thoughts, styles, religions, nationality, education and numerous other traits. Creating and maintaining an environment where differences are valued and respected enhances our ability to recruit and retain the best talent in the marketplace and to provide a work environment that allows all employees to be their best.

Vistra's diversity is evolving, and our Board and management are leading by example. Currently, three of the ten Board members are women, and two of the ten are ethnically diverse. Overall, 28% of the Company's workforce is ethnically diverse. Women currently hold 26% of the Company's senior management positions, and ethnically diverse employees represent 27% of senior management.

During 2021, we launched multiple initiatives to unlock the full potential of our people - and our company - through our diversity, equity, and inclusion efforts. We named our first Chief Diversity Officer in January 2021 who sponsors Vistra's employee-led Diversity, Equity and Inclusion Advisory Council, established in 2020. We continued to expand our Employee Resource Groups (ERG) to promote the appreciation of and communicate awareness of diverse employee groups and communities and their contribution to the overall success of the organization, both internally and externally. Seven new ERGs were formed in 2021, bringing the total number to twelve. New ERGs represent not only diverse cultures, but also employees with disabilities, the LGBTQ+ community and employees engaged in innovation. Further initiatives were launched to support the education, recruitment and retention of current and future employees, with particular emphasis being placed on driving equal access to opportunities throughout the organization. Hiring manager training was developed and deployed to train managers on the importance of skills based hiring and inclusive recruiting processes, and we continue to work with Basic Diversity to develop training for employees to identify bias and develop strong inclusive leaders.

Vistra is active in our communities to promote inclusivity. Vistra's supply chain diversity initiative seeks to reflect our customer base and workforce compositions through creating a diverse supply chain. Through a new partnership with Disability:IN, the leading nonprofit resource for business disability inclusion worldwide, Vistra expanded its commitment to an inclusive global economy. Further, in the second year of Vistra's $10 million five-year commitment to support underserved communities, Vistra provided funding to educational and economic development nonprofits around the country working to transform underserved communities for the better.

Training and Development

We believe the development of employees at all levels is critical to Vistra's current and future success. We have launched key programs to develop leaders at all levels of the organization, including monthly leader meetings for director-level employees focusing on gaining a deeper understanding of Vistra's strategy, developing cross-functional relationships and interacting with senior leadership of the company. Essentials in Leadership provides first time managers with skills to lead organizations in situational leadership, business acumen, identification of communication styles and inclusive communication practices, and exposes them to best practices from across the company. We also revised multiple leadership programs to continue virtually while we continue with remote work during the current pandemic.

Vistra also provides many other training and development programs to help grow and develop employees at every level, including online learning platform courses, learning management system courses, recorded webinars and presentations, self-paced development and employee-specific skill training. Thousands of web-based targeted courses are available to all employees, and the company further supports employees in completing thousands of hours of professional training to support continuing education requirements for their respective professional licenses, including accounting, legal and nuclear. In 2021, Vistra launched a formal mentoring program available to all employees to focus on topics like organizational knowledge, career development, individual development, collaboration and leadership. Over 600 employees participated in 2021 and logged over 4,000 hours of development. In addition, all full-time employees, other than those in a collective bargaining unit, receive a formal performance review guiding development and improving results of the business.

Employee Benefits

Maintaining attractive benefits and pay are important for recruiting and retaining talent. We are committed to maintaining an equitable compensation structure, including performing annual salary reviews by employee category level within significant locations of operations. Eligible full- and part-time employees are provided access to medical, prescription drug, dental, vision, life insurance, accidental death and dismemberment, long-term disability coverage, accident coverage, critical illness coverage and hospital indemnity coverage. Regular full-time employees are eligible for short-term disability benefits, and all employees are eligible for the employee assistance program, parental leave, maternity leave and a 401(k) plan through which the Company matches employee contributions up to 6%.

Wellness

We believe a healthy workforce leads to greater well-being at work and at home. To help keep our workforce healthy, we offer access to on-site medical clinics at six locations. Our healthcare plans are also designed to reward employees for getting annual physicals, age and gender health screenings and immunizations. In addition, our employee medical plans promote mental health and emotional wellness and offer resources for employees seeking assistance. Fitness centers in multiple facilities offer cardio equipment, a selection of free weights and exercise mats. While deferred at times during COVID-19, our employee-led wellness team engages our people to get active and support causes that promote healthy living. With support from the company, the wellness team covers the registration costs for employees to participate in running and cycling events throughout the year.

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.

In January 2021, the Biden administration issued a series of Executive Orders, including one titled *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (the Environment Executive Order) which directed agencies, including the EPA, to review various agency actions promulgated during the prior administration and take action where the previous administration's action conflicts with national objectives. Several of the EPA agency actions discussed below are now subject to this review.

Climate Change

There is continuing attention and interest domestically and internationally about global climate change and how GHG emissions, such as CO_2, contribute to global climate change. GHG emissions from the combustion of fossil fuels, primarily by our coal-fueled-generation plants as well as our natural gas-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 108 million short tons of CO_2 in the year ended 2021.

To manage our environmental impact from our business activities and reduce our emissions profile, Vistra set emissions reduction targets. Vistra is targeting to achieve a 60% reduction in Scope 1 and Scope 2 CO_2 equivalent emissions by 2030 as compared to a 2010 baseline with a long-term goal to achieve net-zero carbon emissions by 2050, assuming necessary advancements in technology and supportive market constructs and public policy. In furtherance of Vistra's efforts to meet its net-zero target, Vistra expects to deploy multiple levers to transition the company to operating with net-zero emissions, including decarbonization of existing business lines and diversification into low-emission businesses, primarily renewables and energy storage. We have already taken or announced significant steps to transform our generation portfolio and reduce the emissions profile of our generation fleet, including:

- *Solar Development Projects* — We began commercial operation of our 180 MW Upton 2 solar facility in 2018. We have announced our plans to develop:
    - up to 768 MW of solar generation facilities in Texas with expected commercial operation dates during 2022-2023, and
    - 300 MW of solar generation facilities at retired or to-be retired plant sites in Illinois with expected commercial operation dates ranging from 2023 to 2025.
- *Battery Energy Storage Projects* — We began commercial operation of our 10 MW battery ESS at our Upton 2 solar facility in 2018 and our 400 MW of battery ESSs at our Moss Landing facility in 2021. We have announced our plans to develop:
    - 260 MW of battery ESS in Texas with an expected commercial operation date in 2022;
    - 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois with expected commercial operation dates ranging from 2023 to 2025, and
    - 350 MW of battery ESS in California with an expected commercial operation date in 2023.
- *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 across various ISOs/RTOs in connection with the Merger.

- *Retirements of Fossil Fuel 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 7,486 MW of fossil-fueled generation facilities in Illinois, Ohio and Texas no later than year-end 2027.

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

GHG Emissions

In July 2019, the EPA finalized a rule that repealed the Clean Power Plan (CPP) that had been finalized in 2015 and established new regulations addressing GHG emissions from existing coal-fueled electric generation units, referred to as the Affordable Clean Energy (ACE) rule. The ACE rule developed emission guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. In response to challenges brought by Environmental groups and certain states, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the ACE rule, including the repeal of the CPP in, January 2021 and remanded the rule to the EPA for further action. In October 2021, the U.S. Supreme Court granted four petitions for certiorari of the D.C. Circuit Court's decision and consolidated the cases for review. The case is now fully briefed and scheduled for oral argument in February 2022. Additionally, in January 2021, the EPA, just prior to the transition to the Biden administration, issued a final rule setting forth a significant contribution finding for the purpose of regulating GHG emissions from new, modified, or reconstructed electric utility generating units. In April 2021, the D.C. Circuit Court granted the EPA's unopposed motion for voluntary vacatur and remand of the GHG significant contribution rule. The ACE rule and the rule on significant contribution are subject to the Environment Executive Order discussed above.

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. RGGI is currently conducting its third program review to be completed in 2022 which may include an updated model rule.

Our generating facilities in Connecticut, Maine, Massachusetts, New Jersey, New York and Virginia emitted approximately 8.5 million tons of CO_2 during 2021. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2021 was approximately $13.68 per allowance. The spot market price of RGGI allowances required to operate our affected facilities during 2022 was approximately $14.01 per allowance on February 22, 2022. 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 were 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 linked Virginia to RGGI in 2021. The Governor of Virginia issued an Executive Order in January 2022 to begin the process of removing the state from RGGI; however, the Virginia General Assembly would need to modify the law to exit the program. At this time, no new laws have passed and Virginia remains in 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 SO_2 emissions and in some regions 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.

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.

In October 2017, the EPA issued a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas' 2009 State Implementation Plan (SIP) and a partial Federal Implementation Plan (FIP). For SO_2, the rule established 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 the 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. For NO_X, the rule adopted the CSAPR's ozone program as BART and for particulate matter, the rule approved Texas's SIP that determines that no electricity generation units are subject to BART for particulate matter. In August 2020, the EPA issued a final rule affirming the prior BART final rule but also included additional revisions that were proposed in November 2019. Challenges to both the 2017 rule and the 2020 rules have been consolidated in the D.C. Circuit Court, where we have intervened in support of the EPA. We are in compliance with the rule, and the retirements of our Monticello, Big Brown and Sandow 4 plants have enhanced our ability to comply. The BART rule is subject to the Environment Executive Order discussed above, and the EPA has stated it is starting a proceeding for reconsideration of the BART rule. The challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's action on reconsideration.

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 Martin Lake generation plant and our now-retired Big Brown and Monticello 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 U.S. Court of Appeals for the Fifth Circuit (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 have revised its previous nonattainment designations and each area at issue would be designated unclassifiable. In August 2020, the EPA issued a Finding of Failure for Texas to submit an attainment plan. In May 2021, the EPA finalized a "Clean Data" determination for the areas surrounding the retired Big Brown and Monticello plants, redesignating those areas as attainment based on monitoring data supporting an attainment designation. In June 2021, the EPA published two notices; one that it was withdrawing the August 2019 Error Correction Rule and a second separate notice denying petitions from Luminant and the State of Texas to reconsider the original nonattainment designations. We, along with the State of Texas, challenged that EPA action and have consolidated it with the pending challenge in the Fifth Circuit Court, with the matter likely being fully briefed by March 2022. In September 2021, the TCEQ considered a proposal for its nonattainment SIP revision for the Martin Lake area and an agreed order to reduce SO_2 emissions from the plant. The proposed agreed order associated with the SIP proposal reduces emission limits as of January 2022. Emission reductions required are those necessary to demonstrate attainment with the NAAQS. The TCEQ's SIP action was finalized in February 2022 and will be submitted to the EPA for review and approval.

Ozone Designations

The EPA issued a final rule in October 2015 lowering the ozone NAAQS from 75 to 70 parts per billion. Areas surrounding our Dicks Creek, Miami Fort and Zimmer facilities in Ohio, our Calumet facility in Illinois and our Wise, Ennis and Midlothian facilities in Texas were designated marginal nonattainment areas in June 2018 by the EPA with an attainment deadline of August 2021. The EPA is required to take action on areas that did not attain by that date by bumping up the region to a "moderate" designation with an attainment deadline of August 2024. States will be required to develop SIPs to address emissions in areas with a higher (more stringent) classification.

In 2016, the EPA finalized the Cross-State Air Pollution Rule Update (CSAPR Update) to address 22 states' obligations with respect to the 2008 ozone NAAQS. In 2019, following challenges by numerous parties, the D.C. Circuit Court found that the CSAPR Update did not fully address certain states' 2008 ozone NAAQS obligations. In October 2020, the EPA proposed an action to address the outstanding 2008 ozone NAAQS obligations in response to the D.C. Circuit Court's 2019 ruling. Vistra subsidiaries filed comments on that rulemaking in December 2020, and the EPA published a final rule in the Federal Register on April 30, 2021 that reduces ozone season NO_X budgets in certain states. We do not believe that the final rule causes a material adverse impact on our future financial results. These actions are subject to the Environment Executive Order discussed above.

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 deadlines for beginning and completing closure vary depending on several factors. 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 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. In August 2020, the EPA issued a final rule establishing a deadline of April 11, 2021 to cease receipt of waste and initiate closure at unlined CCR impoundments. The final rule allows a generation plant to seek the EPA's approval to extend this deadline if no alternative disposal capacity is available and either a conversion to comply with the CCR rule is underway or retirement will occur by either 2023 or 2028 (depending on the size of the impoundment at issue). Prior to the November 2020 deadline, we submitted applications to the EPA requesting compliance extensions under both conversion and retirement scenarios. In November 2020, environmental groups petitioned for review of this rule in the D.C. Circuit Court, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. Also, in November 2020, the EPA finalized a rule that would allow an alternative liner demonstration for certain qualifying facilities. In November 2020, we submitted an alternate liner demonstration for one CCR unit at Martin Lake. In August 2021, we submitted a request to transfer our conversion application for the Zimmer facility to a retirement application following announcement that Zimmer will close by May 31, 2022. In January 2022, the EPA determined that our conversion and retirement applications for our CCR facilities were complete but has not yet made a final determination on any of those applications.

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 have completed closure activities at those ponds at our Baldwin facility.

At our retired Vermilion facility, which was not potentially 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 (PRN) 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. In June 2021, the U.S. Court of Appeals for the Seventh Circuit affirmed the district court's dismissal of the lawsuit, but stated that PRN may refile. 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. In July 2021, we answered that complaint, and 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, which is owned by our subsidiary DMG, and that notice was referred to the Illinois Attorney General. In June 2021, the Illinois Attorney General and the Vermilion County State Attorney filed a complaint in Illinois state court with an agreed interim consent order which the court subsequently entered. Given the violation notices and the enforcement action, the unique characteristics of the site, and the proximity of the site to the only national scenic river in Illinois, we agreed to enter into the interim consent order to resolve this matter. Per the terms of the agreed interim consent order, DMG is required to evaluate the closure alternatives under the requirements of the newly implemented Illinois Coal Ash regulation (discussed below) and close the site by removal. In addition, the interim consent order requires that during the impoundment closure process, impacted groundwater will be collected before it leaves the site or enters the nearby Vermilion river and, if necessary, DMG will be required to install temporary riverbank protection if the river migrates within a certain distance of the impoundments. These proposed closure costs are reflected in the ARO in our condensed consolidated balance sheets (see Note 21 to the Financial Statements).

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. Under the final rule, which was finalized and became effective in April 2021, 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 rule does not mandate closure by removal at any site. In May 2021, we filed an appeal in the Illinois Fourth Judicial District over certain provisions of the final rule. We filed our opening brief in October 2021. Other parties have also filed appeals of certain provisions of the final rule. In October 2021, we filed operating permit applications for 18 impoundments as required by the Illinois coal ash rule, and filed construction permit applications for three of our sites in January 2022.

For all of the above matters, if certain corrective action measures, including groundwater treatment or removal of ash, are required 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. The Illinois coal ash rule was finalized in April 2021 and does not require removal. However, the rule will require us to undertake further site-specific evaluations required by each program. We will not know the full range of decommissioning costs, including groundwater remediation, if any, that ultimately may be required under the Illinois rule until permit applications have been submitted and approved by the IEPA. However, the currently anticipated CCR surface impoundment and landfill closure costs, as reflected in our existing ARO liabilities, 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 minimal at our Illinois plants due to the planned retirements of those plants by 2027. 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 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. Based on these administrative developments, the Fifth Circuit Court agreed to sever and hold in abeyance challenges to those 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. The EPA published a final rule in October 2020 that extends the compliance date for both FGD and bottom ash transport water to no later than December 2025, as negotiated with the state permitting agency. Additionally, the final rule allows for a retirement exemption that exempts facilities certifying that units will retire by December 2028 provided certain effluent limitations are met. In November 2020, environmental groups petitioned for review of the new ELG revisions, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. In July 2021, the EPA announced its intent to revise the ELG rule and moved to hold the 2020 ELG revision litigation in abeyance pending the EPA's completion of its reconsideration rulemaking. Notifications were made to Texas, Illinois and Ohio state agencies on the retirement exemption for applicable coal plants by the regulatory deadline of October 13, 2021.

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

Summary of Risk Factors

The following summarizes the principal factors that make an investment in our company speculative or risky, all of which are more fully described in the Risk Factors section below. This summary should be read in conjunction with the Risk Factors section and should not be relied upon as an exhaustive summary of the material risks facing our business. The following factors could result in harm to our business, financial condition, results of operations, cash flows, and prospects, among other impacts:

Market, Financial and Economic Risks

- Our revenues, results of operations and operating cash flows are affected by price fluctuations in the wholesale power market and other market factors beyond our control.
- We purchase natural gas, coal, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs or disruptions in these fuel markets may have an adverse impact on, our costs, revenues, results of operations, financial condition and cash flows.
- We have retired, announced planned retirements of, and 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.
- 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.
- Competition, changes 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 results of operations and financial condition could be materially and adversely affected if energy market participants continue to construct new generation facilities 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.
- The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, our liquidity, and our results of operations, and any failure to comply with these restrictions could have a material adverse effect on us.
- We may not be able to complete future acquisitions on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy.
- Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties.
- Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations and cash flows.
- We are required to pay the holders of TRA Rights for certain tax benefits, which amounts are expected to be substantial.

Regulatory and Legislative Risks

- Our businesses are subject to ongoing complex governmental regulations and legislation that have adversely impacted, and may in the future adversely impact, our businesses, results of operations, liquidity and financial condition.
- Our cost of compliance with existing and new environmental laws could have a material adverse effect on us.

- Pending or proposed laws or regulations, including those proposed or implemented under the Biden administration, could have a material adverse effect on our businesses, results of operations, liquidity and financial condition.

- Changes to laws, rules or regulations related to market structures in the markets in which we participate may have a material adverse effect on our businesses, results of operation, liquidity and financial condition.

- 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.

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

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.

- 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.

- The operation of our businesses is subject to information security and operational technology risks, including cybersecurity breaches and failure of critical information and operations technology systems. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities, reputational damage, regulatory action, and disrupt business operations, which could have a material adverse effect on us.

- We may suffer material losses, costs and liabilities due to operational risks, regulatory risks, and the risk of nuclear accidents arising from the ownership and operation of the Comanche Peak nuclear generation 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.

- 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.

- We are subject to, and may be materially and adversely affected by, the effects of extreme weather conditions and seasonality.

- The outbreak of COVID-19, or the future outbreak of any other highly infectious or contagious diseases, could have a material and adverse effect on our business, financial condition, results of operations and cash flows.

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

Risks Related to Our Structure and Ownership of our Common Stock

- Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results, or stock price.

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 are affected 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 is subject to wholesale power price moves, which may be significant. 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 in which we operate 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 fuel 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 generation sources, as we have observed in recent years. During periods of over-supply, electricity prices might be depressed. For example, the cost of electricity from renewable resources, such as solar, wind and battery storage systems, has dropped substantially in recent years. In many instances, energy from these sources are bid into the relevant spot market at a price of zero or close to zero during certain times of the day, lowering the clearing price for all power wholesalers in such market. Also, at times there is 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.

Extreme weather events can also materially impact power prices or otherwise exacerbate conditions or circumstances that result in volatility of power prices. For example, in February 2021, the U.S. experienced Winter Storm Uri and extreme cold temperatures in the central U.S., including Texas. This severe weather event substantially increased the demand for natural gas used in our electric power generation business, and the cold further limited the availability of renewable generation across the region contributing to extremely high market prices for natural gas and electricity, which resulted in substantial increases in the costs to procure sufficient fuel supply and increased collateral posting requirements.

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 are unable to hedge or otherwise 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, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs, volatility, or disruption 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, fuel oil, and nuclear fuel for the majority of our power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing availability of such fuels and financial viability of contractual counterparties as well as upon the infrastructure (including mines, rail lines, rail cars, barge facilities, roadways, riverways and natural gas pipelines) available and functioning to serve each generation facility. As a result, we have experienced, and remain 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, if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure. Certain of our generation facilities rely on a limited number of counterparties, such as natural gas suppliers and railcar companies, to provide the necessary fuel. Disputes relating to or non-performance of contractual arrangements, have resulted in, and may continue to result in adverse impacts to our costs, revenues, results of operations, financial condition, and cash flows.

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) are volatile, and the wholesale price for electricity does not always 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 costs which may be higher than planned, 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. Long-term and short-term contracts are subject to risk of non-delivery or claims of force majeure, which may impact our ability to economically recover the value of the contract. In addition, we purchase and sell natural gas and other energy related commodities, and volatility in these markets may affect costs incurred in meeting our obligations. Further, any changes in the costs of natural gas, coal, fuel oil, nuclear fuel 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, or if we are unable to procure these fuels at all, our financial condition, results of operations and cash flows could be materially adversely affected. For example, supply challenges were among the primary drivers of the significant loss experienced in 2021 as a result of Winter Storm Uri.

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 and operating performance. Volatility in market prices for fuel and electricity results from, among other factors:

- demand for energy commodities and general economic conditions, including impacts of inflation and the relative strength or weakness of U.S. dollar compared to other currencies;
- volatility in commodity prices and the supply of commodities, including but not limited to natural gas, coal and fuel oil;
- volatility in market heat rates;
- volatility in coal and rail transportation prices;
- volatility in nuclear fuel and related enrichment and conversion services;
- transmission or transportation disruptions, constraints, congestion, inoperability or inefficiencies of electricity, natural gas or coal transmission or transportation, or other changes in power transmission infrastructure;
- severe, sustained or unexpected weather conditions, including extreme cold, 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;
- importation of liquified natural gas to certain markets;
- 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;
- local, regional, national, or global supply chain constraints or shortages;
- our creditworthiness and liquidity and the willingness of fuel suppliers and transporters to do business with us;
- changes in the credit risk, payment practices, or financial condition of market participants;
- changes in production and storage levels of natural gas, lignite, coal, uranium, diesel and other refined products;
- pandemics and epidemics (including the impacts thereto, or recovery therefrom), 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.

See "*Economic downturns would likely have a material adverse effect on our businesses"* for a discussion of potential risks arising from current U.S. and global economic and geopolitical conditions.

We have retired, announced planned retirements of, and 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 has resulted in the retirement or planned retirement of, and ultimately could result in additional retirements or idling of, generation units. 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. In connection with the closure and remediation of retired generation units, we have spent, and may in the future spend, a significant amount of money, internal resources and time to complete the required closure and reclamation, which could have a material adverse effect on our financial and operating performance.

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. Given our exposure to risks of commodity price movements, we devote a considerable amount of time and effort to the establishment of risk management policies and procedures, as well as the ongoing review of the implementation of these policies and procedures. Additionally, we have processes and controls in place that are designed to monitor and accurately report hedging activities and positions. The policies, procedures, processes and controls in place may not always function as planned and cannot eliminate all the risks associated with these activities, including unauthorized hedging activity, or improper reporting thereof, by our employees in violation of our existing risk management policies and procedures. 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, the impacts of our commodity hedging activities and risk management decisions may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. Additionally, there may be changes to existing laws or regulations that could significantly impact our ability to effectively hedge, which may have a material adverse effect on us.

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 ISOs/RTOs in which we operate are also exposed to risks that another market participant may default on its obligations to pay such ISO/RTO for electricity or services taken, in which case such costs, to the extent not offset by posted security and other protections available to such ISO/RTO, may be allocated to various non-defaulting ISO/RTO 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, changes 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. We expect that we will continue to face intense competition from numerous companies, including new entrants or consolidation of existing competitors, 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, including through certain tax benefits, the construction and development of additional renewable resources as well as increases in energy efficiency investments. 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 new generation facilities 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 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. Additionally, new or existing market participants without, or with less, fossil fuel operations may gain additional market share, or reduce our market share, due to evolving expectations and sentiments of key stakeholders, government, and regulatory authorities regarding our operations and activities.

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 lower 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. The convergence of current global conditions, including sustained inflation, rising interest rates, and the geopolitical climate, could lead to, or accelerate or exacerbate the occurrence of, a significant economic downturn, leading to changes in consumer and counterparty behavior, higher costs of capital, decreases in the value of our existing long-dated contracts, commodity price increases and volatility, supply chain shortages, and other adverse impacts to our business. 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'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;
- credit, security, or collateral requirements, including those relating to volatility in commodity prices;
- general credit availability from banks or other lenders for us and our industry peers;
- investor and lender confidence in and sentiment of the industry, our business, and the wholesale electricity markets in which we operate;
- a material breakdown in or oversight in effectuating 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 ESSs; and
- changes in or the operation of provisions of tax and regulatory laws.

There are also increasing financial risks for companies that own and operate fossil fuel generation as institutional lenders or other sources of capital have become more attentive to sustainable financing practices and some of them may seek commitments on emission reduction targets or expected use or proceeds when providing funding to, or decline to provide funding for companies who produce or utilize fossil fuel energy or that have higher levels of GHG emissions. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists and others concerned about climate change not to provide funding for companies in the broader energy sector. Limitation on our access to, or increases in our cost of, capital could have a material adverse effect on us.

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, due to our non-investment grade credit ratings, counterparties request collateral support (including cash or letters of credit) in order to enter into certain 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 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 phaseout of LIBOR, or the replacement of LIBOR with a different reference rate, 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, 2021, we had approximately $10.7 billion of total indebtedness and approximately $9.4 billion of indebtedness net of cash. Our debt could have negative consequences for our financial condition including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a significant portion of our cash flows 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 July 2017, the United Kingdom's Financial Conduct Authority, which regulates LIBOR, announced that it intends to phase out LIBOR by the end of 2021. LIBOR is the interest rate benchmark used as a reference rate on a portion of our variable rate debt, including our revolving credit facility and interest rate swaps. In November 2020, ICE Benchmark Administration (IBA), the administrator of LIBOR, with the support of the U.S. Federal Reserve and the United Kingdom's Financial Conduct Authority, announced plans to consult on ceasing publication of USD LIBOR on December 31, 2021 for only the one-week and two-month USD LIBOR tenors, and on June 30, 2023 for all other USD LIBOR tenors. While this announcement extends the transition period to June 2023, the U.S. Federal Reserve concurrently issued a statement advising banks to stop new USD LIBOR issuances by the end of 2021. In light of these announcements, the future of LIBOR at this time is uncertain and any changes in the methods by which LIBOR is determined or regulatory activity related to LIBOR's phaseout could cause LIBOR to perform differently than in the past or cease to exist. In anticipation of LIBOR ceasing to exist for affected tenors, we have amended certain of our agreements with LIBOR as the referenced rate to include an alternative benchmark rate or suggested fallback language. Additionally, in light of what we believe to be favorable relationships with lending and financial counterparties, we expect to seek necessary amendments to our remaining debt instruments and other agreements which utilize LIBOR as the referenced rate in the normal course. Further, certain of our agreements which utilize LIBOR as the referenced rate are governed by New York law, and certain of these contracts do not contain any fallback provisions or otherwise contain fallback provisions that lead to replacement rate based on LIBOR or require polling for interbank rates. To the extent that we are unsuccessful in our efforts to amend such contracts prior to the LIBOR transition, we anticipate that the applicable New York legislation would apply to such contracts and would provide a replacement rate for inclusion in such contracts.

Notwithstanding our efforts, these changes may result in interest rates and/or payments that do not correlate over time with the interest rates and/or payments that would have been made on our obligations if LIBOR was available in its current form. Any new contracts would need to reference an alternative benchmark rate or include suggested fallback language. 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 agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, or liquidity, and results of operations, and any failure to comply with these restrictions could have a material adverse effect on us.

The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions that could adversely affect us by limiting our ability to operate our businesses and 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 and/or indentures. The Vistra Operations Credit Facilities and indentures 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/or indentures and are unable to obtain a waiver or amendment, or a default exists and is continuing, the lenders under such agreements or notes, as the case may be, could give notice and declare outstanding borrowings thereunder immediately due and payable. The breach of any covenants or obligations in certain agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, not otherwise waived or amended, could result in a default under the applicable debt obligations and could trigger acceleration of those obligations, which in turn could trigger cross defaults under other agreements governing our debt, and 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 or other sources of available liquidity to post as collateral, we may not be able to manage price volatility effectively or to implement our strategy. A material 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 on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy.

As part of our growth strategy, including our desire to grow our retail platform, we may pursue acquisitions of assets or operating entities. This strategy depends on the Company's ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on favorable terms. 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. In addition, the Company will compete with other companies for these limited acquisition opportunities, which may increase the Company's cost of making acquisitions or limit the Company’s ability to make acquisitions at all. 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 involve unknown risks, 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. If the Company is unable to identify and consummate future acquisitions, it may impede the Company's ability to execute its growth strategy.

Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties.

We have a substantial capital allocation plan intended for investments in renewable assets, including solar development projects and ESSs. As part of our business strategy, we plan to continually assess potential strategic acquisitions or investments in renewable assets, emerging technologies and related projects. Notably, the Company's ability to successfully develop our current renewables projects, or in the future acquire additional renewable assets, may be impacted by the demand for and viability of renewable assets generally, which may vary depending on availability of projects and financing, as well as public policy, financial and tax mechanisms implemented at the state and federal levels to support the development of renewable assets. Various factors could result in increased costs or result in delays or cancellation of our current or future renewable projects, or the loss of, or declines in the value of, our investments in projects including, but not limited to, risks relating to siting, financing, engineering and construction, permitting, interconnection requests, federal and state regulatory approvals, new legislation or regulatory changes impacting the industry, commissioning delays, import tariffs, changes to federal income tax laws, economic events or factors, environmental and community concerns, availability of or requirements for additional funding, enhanced competition, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Further, the recent proliferation of renewable projects has resulted in a large volume of interconnection requests submitted to grid operators, including the markets in which we operate, resulting in significant delays to the approval process and estimated completion dates for our projects and others. Additionally, the increased demand for construction of renewables projects, such as ESSs and solar projects, and other labor market and supply chain constraints have resulted, and may continue to result, in limited availability of qualified specialists, contractors, and necessary services or materials, leading to delays in and higher costs for the development and construction of our current and future planned projects. Should any of these factors occur, our financial position, results of operations, and cash flows could be adversely affected, or our future growth opportunities may not be realized as anticipated.

While certain of our subsidiaries are in various stages of developing and constructing solar generation facilities and ESSs and certain of these projects have signed long-term contracts or made similar arrangements for the sale of electricity, in other cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured power purchase arrangements or other important elements for a successful project. If the project does not proceed as planned, our subsidiaries may remain obligated for certain liabilities even though the project will not be completed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project and could incur additional losses associated with any related contingent liabilities.

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 2021 and determined that no material 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 certain tax attributes and 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 acquired NOLs from its merger with Dynegy; however, Vistra'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 (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. In addition, any ownership change with respect to Vistra could result in additional limitations on our ability to use certain tax attributes, including depreciation, existing at the time of any such ownership change and have an impact on our tax liabilities and on our obligations under the TRA.

Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations and cash flows.

We are subject to the tax laws and regulations of the U.S. federal, state and local governments. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures. The Tax Cuts and Jobs Act of 2017 (TCJA), enacted December 22, 2017, introduced significant changes to current U.S. federal tax law. These changes are complex and continue to be the subject of additional guidance issued by the U.S. Treasury and the Internal Revenue Service. In addition, the reaction to the federal tax changes by the individual states continues to evolve. Our interpretations and assumptions around U.S. tax reform may evolve in future periods as further administrative guidance and regulations are issued, which may materially affect our effective tax rate or tax payments.

U.S. federal, state and local tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities and if not sustained, there could be a material impact on our results of operations and financial condition.

Additionally, U.S. federal income tax reform and changes in other tax laws could adversely affect us. For example, President Biden has set forth several tax proposals that would, if enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to (i) an increase in the U.S. corporate income tax rate and (ii) implementation of a 15% minimum tax on a corporation’s worldwide book income. Congress could consider some or all of these proposals in connection with tax reform to be undertaken by the Biden administration. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on various aspects of our operations. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees could have a material adverse effect on our financial condition, results of operations and cash flows.

We are required to pay the holders of TRA Rights for certain tax benefits, which amounts could 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 $395 million as of December 31, 2021 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 generally 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, plus interest accruing from the due date of the applicable tax return. 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 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 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 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 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 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, which could have a substantial negative impact on our liquidity.

Regulatory and Legislative Risks

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

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, natural gas, carbon offsets and renewable energy certificates, and other commodities. 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. Compliance with, or changes to, the requirements under these legal and regulatory regimes, including those proposed or implemented under the Biden administration, may cause the Company may adversely impact our businesses, results of operations, liquidity, financial condition and cash flows.

Our businesses are subject to numerous state and federal laws (including, but not limited to, PURA, the Federal Power Act, the Natural Gas Policy 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 DOJ, the FTC, the 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, administrative pricing mechanisms (and adjustments thereto), 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. Additionally, Ambit's direct selling business (i) 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 and (ii) may be required to alter its compensation practices in order to comply with applicable federal or state law or regulations. Changes in, revisions to, or reinterpretations of, existing laws and regulations may have a material adverse effect on our businesses, results of operations, liquidity, financial condition and cash flows.

Extreme weather events have resulted, and in the future may result, in efforts by both federal and state government and regulatory agencies to investigate and determine the causes of such events. For example, as a result of Winter Storm Uri, we received a civil investigative demand from the Attorney General of Texas as well as a request for information from ERCOT, NERC, and other regulatory bodies related to this event and may receive additional inquiries. Such efforts have resulted, and in the future may result, in changes in laws or regulations that impact our industry and businesses including, but not limited to, additional requirements for winterization of various facets of the electricity supply chain including generation, transmission, and fuel supply; improvements in coordination among the various participants in the electricity supply chain during any future event; restrictions or limitations on the types of plans permitted to be offered to customers; potential revisions to method or calculation of market compensation and incentives relating to the continued operation of assets that only run periodically, including during extreme weather events or other times of scarcity; and other potential legislative and regulatory corrective actions that may be taken. Previously announced or future legal proceedings, regulatory actions, investigations, or other administrative proceedings involving market participants may result lead to adverse determinations or other findings of violations of laws, rules or regulations, any of which may impact the ability of market participants to satisfy, in whole or in part, their respective obligations. We are continuing to monitor and evaluate the impacts of this developing situation but at this time we cannot estimate the likelihood or impacts of any legislative or regulatory changes or actions (including enforcement actions that may be brought against various market participants) that may occur as a result of the event on our business, financial condition, results of operations, or cash flows.

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 federal 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 proposed Cross-State Air Pollution Rule Update, the ACE rule and any proposed or future actions to replace the ACE rule, and actions under 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, which could have a material adverse effect on us.

We could be materially and adversely affected if new federal or state legislation or regulations are adopted to address global climate change that could require efforts that exceed or are more expensive than our currently planned initiatives 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 developed emissions guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. In January 2021, the ACE rule was vacated by the D.C. Circuit Court and remanded to the EPA for further consideration in accordance with the court's ruling. The D.C. Circuit's decision has been appealed to the U.S. Supreme Court and oral argument is scheduled for February 2022. The EPA may develop a more stringent and more encompassing rule to replace the ACE rule in its remand proceeding and has been directed by the Biden Administration to review this rule and others promulgated by the EPA during the Trump Administration. Prior to the vacatur and remand, states where we operate coal plants (Texas, Illinois and Ohio) had begun the development of their state plans to comply with the now-vacated 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 that could require efforts that exceed or are more expensive than our currently planned initiatives or if we are subject to lawsuits for alleged damage to persons or property resulting from GHG emissions.

Additionally, in January 2021, President Biden issued written notification to the United Nations of the U.S.'s intention to rejoin the Paris Agreement, effective in February 2021. Although the Paris Agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions, and various corporations, investors and U.S. states and local governments have previously pledged to further the goals of the Paris Agreement. Additionally, the Biden Administration has directed certain agencies to submit a plan to the National Climate Task Force to achieve a carbon-pollution-free electricity sector by 2035. The Company's plan to transition to clean power generation sources and reduce its GHG emissions may not be completed in this timeframe and we may not otherwise achieve our sustainability and emissions reduction targets as expected. Accordingly, we may be required to accelerate or change our targets, incur additional expenses, and/or adjust or cease certain operations as a result of newly implemented federal and/or state regulations to reduce future carbon emissions.

Luminant's mining operations are subject to RCT oversight.

We currently own and operate, or are in the process of reclaiming, various 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, multiple 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 in Texas. 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 generation asset, 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 is projected to spend approximately $265 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 reputational 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 U.S. retail businesses partially depends on state regulatory policies that establish the structure, rules, terms and conditions on which services are offered to retail customers. Specifically, the public utility commissions and/or the attorney generals of the various jurisdictions in which the Retail segment operates may at any time initiate an investigation into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements. These state policies and investigations, which can include controls on the retail rates our retail businesses can charge, the imposition of additional costs on sales, restrictions on our ability to obtain new customers through various marketing channels and disclosure requirements, investigations into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements, can affect the competitiveness of our retail businesses. Any removal or revocation of a REP certification would mean that we would no longer be allowed to provide electricity service to retail customers in the applicable jurisdiction, and such decertification could have a material adverse effect on us. Additionally, state or federal imposition of net metering or renewable portfolio standard programs can make it more or less expensive for retail customers to supplement or replace their reliance on grid power. Our retail businesses have limited ability to influence development of these state rules, regulations and policies, and our business model may be more or less effective, depending on changes to the regulatory environment.

Operational Risks

Volatile power supply costs and demand for power 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;
- out-of-market payments, uplifts, or other non-pass through charges, 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, transmission and distribution outages, demand-side management programs, competition and economic conditions, such as Winter Storm Uri in February 2021.

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 advanced persistent cyber-based security threats and integrity risk. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities, reputational damage, regulatory action, 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, and those of our vendors and suppliers, are susceptible to threats which could compromise confidentiality, integrity or availability. While we have controls in place designed to protect our infrastructure, such breaches and threats are becoming increasingly sophisticated and complex, requiring continuing evolution of our program. 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, maintain confidentiality, availability and integrity of our restricted data, access retail customer information and limit communication with third parties, which could have a material adverse effect on us.

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. Concerns about data privacy have led to increased regulation and other actions that could impact our businesses and changes in data privacy and data protection laws and regulations or any failure to comply with such laws and regulations could adversely affect our business and financial results. 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 our infrastructure, we have been, and will likely continue to be, subject to attempts at phishing and other cybersecurity intrusions. International conflict increases the risk of state-sponsored cyber threats and escalated use of cybercriminal and cyber-espionage activities. In particular, the current geopolitical climate has further escalated cybersecurity risk, with various government agencies, including the U.S. Cybersecurity & Infrastructure Security Agency, issuing warnings of increased cyber threats, particularly for U.S. critical infrastructure. 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 marketplace and our industry, and there is no assurance that we will be able to prevent any such impacts in the future. If a material breach of our information technology systems were to occur, the critical operational capabilities and reputation of our business may be adversely affected, customer confidence may be diminished, and our business may be subject to substantial legal or regulatory scrutiny and claims, any of which may contribute to potential legal or regulatory actions against the Company, loss of customers and otherwise have a material adverse effect on us. Any loss or disruption of critical operational capabilities to support our generation, commercial or retail operations, loss of customers, or 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. 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.

We may suffer material losses, costs and liabilities due to operation risks, regulatory risks, and the risk of nuclear accidents arising from the 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, insider threat, third-party compromise 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, including nation-state attacks or organized cyber 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 environmental impacts, 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 flows 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 our revenues and results of operations, and we 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 extreme weather, 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, including increasing pressure on firms that provide insurance to companies that own and operate fossil fuel generation, 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 flows 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.

The EPA has been directed by the Biden Administration to review a number of environmental rules adopted by the EPA during the Trump Administration, including Coal Combustion Residuals (CCR) rule, the Emissions Limitation Guidelines (ELG) rule, the Affordable Clean Energy (ACE) rule and the PM and Ozone National Ambient Air Quality Standards (NAAQS) rules. All of these rules may significantly and adversely impact our existing coal fleet and may lead to accelerated plant closure timeframes. In addition, the expected revisions to the ACE rule and NAAQS also have the potential to adversely impact our gas-fired units.

The EPA is reviewing applications submitted by us to extend closure deadlines for many of our CCR impoundments. The scope and cost of that closure work could increase significantly based on new requirements imposed by the EPA or state agencies. There is no assurance that our current assumptions for closure activities will be accepted by EPA. If ponds must be closed sooner than anticipated, plant closures timeframes may be accelerated.

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.

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 are subject to the effects of extreme weather conditions, including sustained or extreme cold or hot temperatures, hurricanes, floods, droughts, storms, fires, earthquakes or other natural disasters, which could stress our generation facilities and grid reliability, limit our ability to procure adequate fuel supply, or result in outages, damage or 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, certain extreme weather events have previously affected, and may in the future, 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 has resulted, and may in the future result, in (i) 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, (ii) the failure of equipment at our generation facilities, (iii) a decrease in the availability of, or increases in the cost of, fuel sources, including natural gas, diesel and coal, or (iv) unpredictable curtailment of customer load by the applicable ISO/RTO in order to maintain grid reliability, resulting in the realization of lower wholesale prices or retail customer sales. For example, Winter Storm Uri in February 2021 had a material impact on our results of operations.

Additionally, climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, and other climatic events, could disrupt our operations and cause us to incur significant costs to prepare for or respond to these effects.

Weather 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, as well as significantly limiting the supply of, or increasing the cost of our fuel supply, each of which could have a material adverse effect on our business, results of operations, financial condition and liquidity.

The outbreak of COVID-19, or the future outbreak of any other highly infectious or contagious diseases, could have a material and adverse effect on our business, financial condition, and results of operations.

The outbreak of the COVID-19 pandemic has adversely impacted economic activity and conditions worldwide, and we are responding to the outbreak by taking steps to mitigate the potential risks to us posed by its spread. We continue to examine the impacts of the pandemic on our workforce, liquidity, reliability, cybersecurity, customers, suppliers, along with other macroeconomic conditions and cannot currently predict whether COVID-19 will have a material impact on our results of operations, financial condition, and cash flows. Additionally, global recovery and transition from COVID-19 could have a material impact on supply, business and commodity market fundamentals on a national and global scale.

Because we are deemed a critical infrastructure provider that provides a critical service to our customers, we must keep our employees who operate our businesses safe and minimize unnecessary risk of exposure. We have updated and implemented our company-wide pandemic plan to address specific aspects of the COVID-19 pandemic. This plan guides our emergency response, business continuity, and the precautionary measures we are taking on behalf of employees and the public. We will continue to monitor developments affecting both our workforce and our customers, and we will take additional precautions that we determine are necessary in order to mitigate the impacts. In particular, we have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities including requiring, for both employees and contractors, social distancing where possible and requiring the use of appropriate personal protective equipment in certain circumstances. We have implemented work-from-home policies and other safety measures where appropriate, including, but not limited to, encouraging vaccinations and boosters, answering screening questions and temperature testing at all of our locations for unvaccinated employees, contractors, and other essential visitors and closing our facilities to non-essential visitors. While our systems and operations remain vulnerable to cyber-attacks and other disruptions due in part to the fact that a portion of our workforce continues to work remotely, we have implemented physical and cyber-security measures to ensure that our systems remain functional in order to both serve our operational needs with a remote workforce and keep them running to ensure uninterrupted service to our customers. We will continue to review and modify our plans as conditions change.

Measures to control the spread of COVID-19, including restrictions on travel, public gatherings, and certain business operations, have affected the demand for the products and services of many businesses in the areas in which we operate and disrupted supply chains around the world. The full scope and extent of the impacts of COVID-19 on our operations are unknown at this time. However, COVID-19 or another pandemic could have material and adverse effects on our results of operations, financial condition and cash flows due to, among other factors, a protracted slowdown of broad sectors of the economy, changes in demand or supply for commodities, significant changes in legislation or regulatory policy to address the pandemic (including prohibitions on certain marketing channels, moratoriums or conditions on disconnections or limits or restrictions on late fees), reduced demand for electricity (particularly from commercial and industrial customers), increased late or uncollectible customer payments, negative impacts on the health of our workforce, a deterioration of our ability to ensure business continuity (including increased vulnerability to cyber and other information technology risks as a result of a significant portion of our workforce continuing to work from home), and the inability of the Company's contractors, suppliers, and other business partners to fulfill their contractual obligations.

Despite our efforts to manage these impacts to the Company, their ultimate impact also depends on factors beyond our knowledge or control, including the duration and severity of this outbreak as well as third-party actions taken to contain its spread and mitigate its public health effects. To the extent COVID-19 adversely affects our business and financial results, it may also have the effect of hastening, heightening, or increasing the negative impacts of, many of the other risks described in this *Risk Factors* section.

Changes in technology, increased electricity conservation efforts, or energy sustainability 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, hydrogen, micro turbines, photovoltaic (solar) cells, batteries and concentrated solar thermal devices, along with improvements in traditional technologies. Such technological advances may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, and have resulted, and are expected to continue to reduce the costs of power production or storage, which may result in the obsolescence of certain of our operating assets. 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 and our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services and products that meet customer demands and evolving industry standards. 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 or distributed 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. Additionally, increased governmental and consumer focus on energy sustainability efforts, including desire for, or incentives related to, the development, implementation and usage of low-carbon technology, may result in decreased demand for the traditional generation technologies that we currently own and operate.

We may potentially be affected by emerging technologies that may over time affect change in capacity markets and the energy industry overall including 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. Additionally, large-scale cryptocurrency mining is becoming increasingly prevalent in certain markets, including ERCOT, and many of these cryptocurrency mining facilities are "behind-the-meter." 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. Further, we are facing an increasingly competitive market for hiring and retaining skilled employees in certain skill areas, which is exacerbated by the effects of the COVID-19 pandemic and increased acceptance of hiring remote working employees by our competitors and other companies. Difficulties in attracting and retaining highly qualified skilled employees may restrict our ability to adequately support our business needs and/or result in increased personnel costs. In addition, effective succession planning is important to our long-term success. Failure to timely and effectively ensure transfer of knowledge and smooth transitions involving senior management and other key personnel could hinder our strategic planning and execution.

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

As of December 31, 2021, we had approximately 1,400 employees covered by collective bargaining agreements. The terms of all current collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal-, natural gas- and nuclear-fueled generation operation, as well as some battery operations, expire on various dates between March 2022 and May 2024, 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. We have in place strike contingency plans that address the procurement of replacement labor. 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 is a holding company and its ability to obtain funds from its subsidiaries is structurally subordinated to existing and future liabilities of its subsidiaries.

Vistra is a holding company that does not conduct any business operations of its own. As a result, Vistra's cash flows and ability to meet its obligations are largely dependent upon the operating cash flows of Vistra's subsidiaries and the payment of such operating cash flows to Vistra in the form of dividends, distributions, loans or otherwise. These subsidiaries are separate and distinct legal entities from Vistra and have no obligation (other than any existing contractual obligations) to provide Vistra with funds to satisfy its obligations. Any decision by a subsidiary to provide Vistra 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.

Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results or stock price.

Companies across all industries are facing evolving expectations or increasing scrutiny from stakeholders related to their approach to ESG matters. For Vistra, climate change, safety and stakeholder relations remain primary focus areas, and changing expectations of our practices and performance across these and other ESG areas may impose additional costs or create exposure to new or additional risks. Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities and other groups directly impacted by our activities, as well as governments and government agencies, investor advocacy groups, certain institutional investors, investment funds and others which are increasingly focused on ESG practices. Certain financial institutions have announced policies to presently or in the future cease investing or to divest investments in companies that derive any or a specified portion of their income from, or have any or a specified portion of their operations in, fossil fuels.

While we are strategically focused on successfully adapting to the energy transition and strongly committed to our ESG practices and performance (including transparency and accountability thereof), our plans to transition to clean power generation sources and reduce our carbon footprint may not be completed in the timeframe and we may not achieve our targets as expected, which could impact stakeholder trust and confidence. Any such erosion of stakeholder trust and confidence, evolving expectations from stakeholders on such ESG issues, and such parties' resulting actions or decisions about our company and our industry could have negative impacts on our business, operations, financial results, and stock price, including:

- negative stakeholder sentiment toward us and our industry, including concerns over environmental or sustainability matters and potential changes in federal and state regulatory actions related thereto;
- loss of business or loss of market share, including to competitors who do not have any, or comparable amounts, of operations involving fossil fuels;
- loss of ability to secure growth opportunities;
- the inability to, or increased difficulties and costs of, obtaining services, materials, or insurance from third parties;
- reductions in our credit ratings or increased costs of, or limited access to, capital;
- delays in project execution;
- legal action;
- inability or limitations on ability to receive applicable government subsidies, or competitors with smaller or no fossil operations receiving subsidies for which we are not eligible, or in larger amounts;

- increased regulatory oversight;
- loss of ability to obtain and maintain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms;
- changing investor sentiment regarding investment in the power and utilities industry or our company;
- restricted access to and cost of capital; and
- loss of ability to hire and retain top talent.

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.

Holders of our preferred stock may have interests and rights that are different from our common stockholders.

We are permitted under our certificate of incorporation to issue up to 100,000,000 shares of preferred stock. We can issue shares of our preferred stock in one or more series and can set the terms of the preferred stock without seeking any further approval from our common stockholders. Any preferred stock that we issue may rank ahead of our common stock in terms of dividend priority or liquidation premiums and may have greater voting rights than our common stock, which could dilute the value of our common stock to current stockholders and could adversely affect the market price of our common stock. As of December 31, 2021, 1,000,000 shares of Series A Preferred Stock and 1,000,000 shares of Series B Preferred Stock were issued and outstanding. The Preferred Stock represents a perpetual equity interest in the Company and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date; *provided*, the Company may redeem the Preferred Stock at the specified times (or upon certain specified events) at the applicable redemption price set forth in the certificate of designation of each of the Series A Preferred Stock and Series B Preferred Stock, respectively (Certificates of Designation). The Preferred Stock is not convertible into or exchangeable for any other securities of the Company. Upon the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, after payment or provision for payment of the debts and other liabilities of the Company, the holders of Preferred Stock will be entitled to receive, pro rata and in preference to the holders of any other capital stock, an amount per share equal to $1,000 plus accrued and unpaid dividends thereon, if any.

Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock and the holders of at least two-thirds of the outstanding Series B Preferred Stock, voting as a separate class, we may not adopt any amendment to our certificate of incorporation (including the applicable Certificates of Designation) that would have a material adverse effect on the powers, preferences, duties, or special rights of such series of Preferred Stock, subject to certain exceptions. In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock and the holders of at least two-thirds of the outstanding Series B Preferred Stock, voting as a class together with the holders of any parity securities upon which like voting rights have been conferred and are exercisable, we may not: (i) create or issue any senior securities, (ii) create or issue any parity securities (including any additional Preferred Stock) if the cumulative dividends payable on the outstanding Preferred Stock (or parity securities, if applicable) are in arrears; (iii) create or issue any additional Preferred Stock or any parity securities with an aggregate liquidation preference, together with the issued and outstanding Preferred Stock and any parity securities that are then outstanding, of greater than $2.5 billion, and (iv) engage in any Transaction that results in a Covered Disposition (as such terms are defined in the Certificates of Designation).

In addition, holders of the Preferred Stock are entitled to receive, when, as, and if declared by our Board, semi-annual cash dividends on the Preferred Stock, which are cumulative from the applicable initial issuance date of the Preferred Stock and payable in arrears, and unless full cumulative dividends have been or contemporaneously are being paid or declared on the Preferred Stock, we may not (i) declare or pay any dividends on any junior securities, including our common stock, or (ii) redeem or repurchase any parity securities or junior securities, subject to limited exceptions set forth in the Certificates of Designation. There is no assurance that the Board will declare, or that we will pay, any dividends on our Preferred Stock in the future. The holders of Preferred Stock (along with any parity securities then outstanding with similar rights) are entitled to elect two additional directors in the event any dividends on Preferred Stock are in arrears for three or more semi-annual dividend periods (whether or not consecutive), and such directors may have competing and different interests to those elected by our common stockholders. The dividend rate for the Series A Preferred Stock from and including the initial issuance date of October 15, 2021 until the first reset date of October 15, 2026 will be 8.0% per annum of the $1,000 liquidation preference per share of Series A Preferred Stock. The dividend rate for the Series B Preferred Stock from and including the initial issuance date of December 10, 2021 until the first reset date of December 15, 2026 will be 7.0% per annum of the $1,000 liquidation preference per share of Series B Preferred Stock. On and after the first reset date of the Series A Preferred Stock, the dividend rate on the Series A Preferred Stock for each subsequent five-year period (each, a Reset Period) will be adjusted based upon the applicable Treasury rate, plus a spread of 6.93% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.07%. On and after the first reset date of the Series B Preferred Stock, the dividend rate on the Series B Preferred Stock for each Reset Period will be adjusted based upon the applicable Treasury rate, plus a spread of 5.74% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.26%. In the event that the Company does not exercise its option to redeem all the shares of Preferred Stock within 120 days after the first date on which a Change of Control Trigger Event (as defined in the Certificate of Designation) occurs, the then-applicable dividend rate for the Preferred Stock will be increased by 5.00%.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

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

Facility	Location	ISO/RTO	Technology	Primary Fuel (a)	Net Capacity (MW) (b)	Ownership Interest (c)
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%
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%
Comanche Peak	Glen Rose, TX	ERCOT	Nuclear	Nuclear	2,300	100%
Upton 2	Upton County, TX	ERCOT	Solar/Battery	Renewable	180	100%
Total Texas Segment					17,623	
Fayette	Masontown, PA	PJM	CCGT	Natural Gas	726	100%
Hanging Rock	Ironton, OH	PJM	CCGT	Natural Gas	1,430	100%

Facility	Location	ISO/RTO	Technology	Primary Fuel (a)	Net Capacity (MW) (b)	Ownership Interest (c)
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	349	100%
Washington	Beverly, OH	PJM	CCGT	Natural Gas	711	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	Fuel 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	Fuel Oil	16	100%
Bellingham	Bellingham, MA	ISO-NE	CCGT	Natural Gas	566	100%
Blackstone	Blackstone, MA	ISO-NE	CCGT	Natural Gas	544	100%
Casco Bay	Veazie, ME	ISO-NE	CCGT	Natural Gas	543	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%
Independence	Oswego, NY	NYISO	CCGT	Natural Gas	1,212	100%
Total East Segment					12,093	
Moss Landing 1 & 2	Moss Landing, CA	CAISO	CCGT	Natural Gas	1,020	100%
Moss Landing	Moss Landing, CA	CAISO	Battery	Renewable	400	100%
Oakland	Oakland, CA	CAISO	CT	Fuel Oil	110	100%
Total West Segment					1,530	
Coleto Creek	Goliad, TX	ERCOT	ST	Coal	650	100%
Baldwin	Baldwin, IL	MISO	ST	Coal	1,185	100%
Edwards	Bartonville, IL	MISO	ST	Coal	585	100%
Newton	Newton, IL	MISO	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%
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%
Total Sunset Segment					7,486	
Total capacity					38,732	

(a) Renewable represents generation assets fueled by renewable sources including energy storage and solar, which do not have significant fuel costs.
(b) 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.
(c) 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.

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

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, 2021, Vistra had long-term agreements to procure renewable energy credits from approximately 915 MW of renewable generation. 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 occurred 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%, 97% and 96% in 2021, 2020 and 2019, respectively.

We have contracts in place for all of our 2022 and 2023 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.

Natural Gas — Our natural gas-fueled generation fleet is comprised of 23 CCGT generating facilities totaling 19,512 MW and 13 peaking generation facilities totaling 5,022 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.

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 and coal purchased and transported by railcar at the Coleto Creek and Martin Lake generation facilities.

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 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 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's mines, on a regular basis, and if it believes a violation of the Mine Act or any health or safety standard or other regulation has occurred, it may issue a citation or order, generally accompanied by a proposed fine or assessment. Such citations and orders can be contested and appealed, which often results in a reduction of the severity and amount of fines and assessments and sometimes results in dismissal. Disclosure of MSHA citations, orders and proposed assessments are provided in Exhibit 95.1 to this annual report on Form 10-K.

PART II

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

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

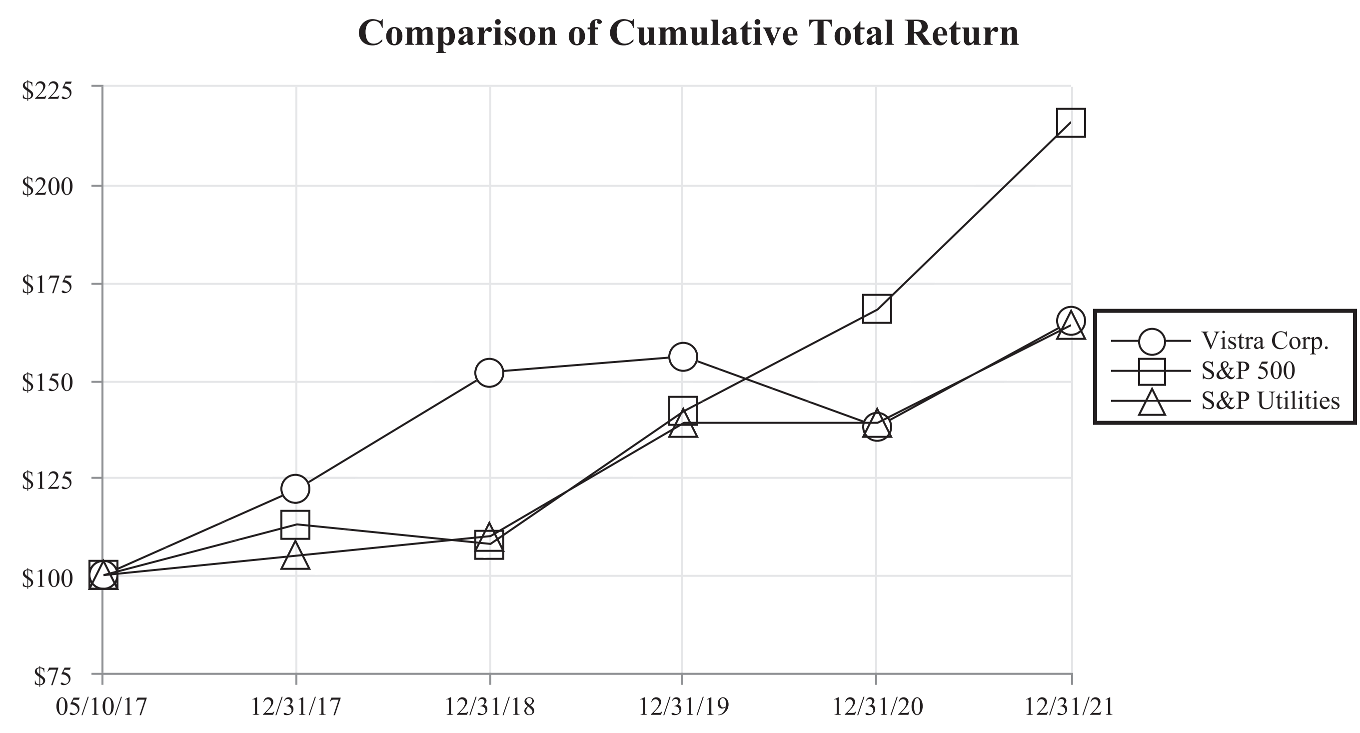
Since May 10, 2017, Vistra's common stock has been listed on the NYSE under the symbol "VST".

As of February 22, 2022, there were 448,803,986 shares of common stock issued and outstanding and 620 stockholders of record.

In November 2018, we announced that the Board had adopted a common stock 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 2022, our Board declared a quarterly dividend of $0.17 per share that will be paid in March 2022. 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'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, 2021 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'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, 2021.

	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, 2021	—	$ —	—	$ 2,000
November 1 - November 30, 2021	5,094,030	$ 20.22	5,094,030	$ 1,897
December 1 - December 31, 2021	14,236,335	$ 21.50	14,236,335	$ 1,591
For the quarter ended December 31, 2021	19,330,365	$ 21.16	19,330,365	$ 1,591

In October 2021, we announced that the Board had authorized a new share repurchase program (Share Repurchase Program) under which up to $2.0 billion of our outstanding common stock may be repurchased. The Share Repurchase Program became effective on October 11, 2021. The Share Repurchase Program supersedes the $1.5 billion share repurchase program previously announced in September 2020, which had $1.325 billion of remaining authorization as of September 30, 2021. As an initial step in our broader capital allocation plan, we intend to use all of the net proceeds from our October 2021 Series A Preferred Stock offering to repurchase shares of our outstanding common stock. We expect to complete repurchases under the Share Repurchase Program by the end of 2022.

Under the Share Repurchase Program, any purchases of shares of the Company's stock may be repurchased from time to time 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.

See Note 14 to the Financial Statements for more information concerning the Share Repurchase Program.

Item 6. [RESERVED]

Not applicable.

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

The discussion below, as well as other portions of this annual report on Form 10-K, contain forward-looking statements within the meaning of Section 27A of the Securities Act, Section 21E of the Exchange Act and the Private Securities Litigation Reform Act of 1995. In addition, management may make forward-looking statements orally or in other writing, including, but not limited to, in press releases, quarterly earnings calls, executive presentations, in the annual report to stockholders and in other filings with the SEC. Readers can usually identify these forward-looking statements by the use of such words as "may," "will," "should," "likely," "plans," "projects," "expects," "anticipates," "believes" or similar words. These statements involve a number of risks and uncertainties. Actual results could materially differ from those anticipated by such forward-looking statements. For more discussion about risk factors that could cause or contribute to such differences, see Part I, Item 1A "Risk Factors" and other risks discussed herein. Forward-looking statements reflect the information only as of the date on which they are made. The Company does not undertake any obligation to update any forward-looking statements to reflect future events, developments, or other information. If Vistra does update one or more forward-looking statements, no inference should be drawn that additional updates will be made regarding that statement or any other forward-looking statements. This discussion is intended to clarify and focus on our results of operations, certain changes in our financial position, liquidity, capital structure and business developments for the periods covered by the consolidated financial statements included under Part II, Item 8 of this annual report on Form 10-K for the year ended December 31, 2021. This discussion should be read in conjunction with those consolidated financial statements and the related notes and is qualified by reference to them.

The following discussion and analysis of our financial condition and results of operations for the years ended December 31, 2021, 2020 and 2019 should be read in conjunction with our consolidated financial statements and the notes to those statements. The discussion and analysis of our financial condition and results of operations for the year ended December 31, 2019 and for the year ended December 31, 2020 compared to the year ended December 31, 2019 are included in Item 7. *Management's Discussion and Analysis of Financial Condition and Results* in our 2020 Form 10-K and are incorporated herein by reference.

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

Operating Segments

Vistra has six reportable segments: (i) Retail, (ii) Texas, (iii) East (iv) West, (v) Sunset and (vi) Asset Closure. See Note 20 to the Financial Statements for further information concerning our reportable business segments.

Significant Activities and Events and Items Influencing Future Performance

Winter Storm Uri

In February 2021, the U.S. experienced an unprecedented Winter Storm Uri, bringing extreme cold temperatures to the central U.S., including Texas. On February 12, 2021, the Governor of Texas declared a state of disaster for all 254 counties in the State in response to the then-forecasted weather conditions. The declaration certified that severe winter weather posed an imminent threat due to prolonged freezing temperatures, heavy snow, and freezing rain statewide. On February 14, 2021, President Biden issued a federal emergency declaration for all 254 Texas counties.

As part of its annual winter season preparations, our power plant teams executed a significant winter preparedness strategy, which included installing windbreaks and large radiant heaters to supplement existing freeze protection and insulation and performing preventative maintenance on freeze protection equipment such as the insulation and automatic circuitry designed to keep pipes at the power plants from freezing. In addition, in anticipation of Winter Storm Uri we took additional steps to prepare, including procuring additional demineralized water supply trailers to ensure sufficient water availability to run for extended periods and verifying that freeze protection circuits were operational.

This severe weather resulted in surging demand for power, gas supply shortages, operational challenges for generators, and a significant load shed event (*i.e.*, involuntary outages to customers across the system for varying periods of time) that was ordered by ERCOT beginning on February 15, 2021 and continuing through February 18, 2021. Despite these challenges, we estimate that our fleet generated approximately 25 to 30% of the power on the grid during the height of the outages, as compared to our approximately 18% market share.

The weather event resulted in a $2.2 billion negative impact on the Company's pre-tax earnings in the year ended December 31, 2021 (see Note 1 to the Financial Statements), after taking into account approximately $544 million in securitization proceeds Vistra expects to receive from ERCOT as further described below. The primary drivers of the loss were the need to procure power in ERCOT at market prices at or near the price cap due to lower output from our natural gas-fueled power plants driven by natural gas deliverability issues and our coal-fueled power plants driven by coal fuel handling challenges, high fuel costs, and high retail load costs.

As part of the 2021 regular Texas legislative sessions and in response to extraordinary costs incurred by electricity market participants during Winter Storm Uri, the Texas legislature passed House Bill (HB) 4492 for ERCOT to obtain financing to distribute to load-serving entities (LSEs) that were charged and paid to ERCOT exceptionally high price adders and ancillary service costs during Winter Storm Uri. In October 2021, the PUCT issued a debt obligation order approving ERCOT's $2.1 billion financing and the methodology for allocation of proceeds to the LSEs. In December 2021, ERCOT finalized the amount of allocations to the LSEs, and we expect to receive $544 million in proceeds from ERCOT in the second quarter of 2022. We concluded that the threshold for recognizing a receivable was met in December 2021 as the amounts to be received are determinable and ERCOT was directed by its governing body, the PUCT, to take all actions required to effectuate the $2.1 billion funding approved in the debt obligation order. Accordingly, we recognized the $544 million in expected proceeds as an expense reduction in the fourth quarter of 2021 within fuel, purchased power costs and delivery fees in our consolidated statements of operation.

We continue to be subject to the outcome of potential litigation arising from this event (including any litigation that we may pursue or be a party to); or any corrective action taken by the State of Texas, ERCOT, the RCT, or the PUCT to resettle pricing across any portion of the supply chain that is currently being considered or may be considered by any such parties. The Texas legislature also continues to consider potential legislation, such as Senate Bill (SB) 1580, which was passed in May 2021. SB 1580 may impact the total amount of balances owed by electric cooperatives to the market. The potential impact of this legislation is uncertain as the final details will be specific to each electric cooperative.

There have been several announced efforts by the state and federal governments and regulatory agencies to investigate and determine the causes of this event and its impact on consumers. We have received a civil investigative demand from the Attorney General of Texas as well as requests for information from ERCOT, NERC and other regulatory bodies related to this event and may receive additional inquiries. We are cooperating with these entities and have responded to these requests. Those efforts may result in changes in regulations that impact our industry including but not limited to additional requirements for winterization of various facets of the electricity supply chain including generation, transmission, and fuel supply; improvements in coordination among the various participants in the electricity and natural gas supply chains during any future event; potential revisions to the method or calculation of market compensation and incentives relating to the continued operation of assets that only run periodically, including during extreme weather events or other times of scarcity; and restrictions or limitations on the types of plans permitted to be offered to customers. We are continuing to monitor this situation as it develops. The full impact of litigation or any impacts of any legislative or regulatory changes or actions (including enforcement actions that may be brought against various market participants) that may occur as a result of the event could have a material impact on our business, financial condition, results of operations, or cash flows, but cannot be estimated at this time. See Note 13 to the Financial Statements for further discussion of these matters.

In response to the storm, Vistra committed to donate $5 million to assist Texas communities and individuals meet their most pressing needs, including support for food banks and food pantries, critical needs, bill payment assistance, and more. Vistra also assured residential customers across its retail brands that they would not see any near-term impact on their rates due to the winter weather event, though bills could increase due to high usage during the cold weather period in February 2021.

Furthermore, Vistra has taken or intends to take various actions to improve its risk profile for future weather-driven volatility events, including investing in improvements to further harden its coal fuel handling capabilities and to further weatherize its ERCOT fleet for even colder temperatures and longer durations; carrying more backup generation into the peak seasons after accounting for weatherization investments and ERCOT market improvements implemented going forward; contracting for incremental gas storage to support its gas fleet; adding additional dual fuel capabilities at its gas steam units and increasing fuel oil inventory at its existing dual fuel sites; participating in processes with the PUCT and ERCOT for registration of gas infrastructure as critical resources with the transmission and distribution utilities and for enhanced winterization of both gas and power assets in the state; and engaging in processes to evaluate potential market reforms.

Climate Change, Investments in Clean Energy and CO_2 Reductions

Environmental Regulations — We are subject to extensive environmental regulation by governmental authorities, including the EPA and the environmental regulatory bodies of states in which we operate. Environmental regulations could have a material impact on our business, such as certain corrective action measures that may be required under the CCR rule and the ELG rule. See "Item 1. Business – Environmental Regulations and Related Considerations," and "Item 1A. Risk Factors – Regulatory and Legislative Risks" and Note 13 to the Financial Statements. However, such rules and the regulatory environment are continuing to evolve and change, and we cannot predict the ultimate effect that such changes may have on our business.

Emissions Reductions — Vistra is targeting to achieve a 60% reduction in Scope 1 and Scope 2 CO_2 equivalent emissions by 2030 as compared to a 2010 baseline with a long-term goal to achieve net-zero carbon emissions by 2050, assuming necessary advancements in technology and supportive market constructs and public policy. In furtherance of Vistra's efforts to meet its net-zero target, Vistra expects to deploy multiple levers to transition the company to operating with net-zero emissions.

Green Finance Framework — In December 2021, we announced the publication of our Green Finance Framework, which allows us to issue green financial instruments to fund new or existing projects that support renewable energy and energy efficiency with alignment to our ESG initiatives. See *Preferred Stock Offerings* below for discussion of the Series B Preferred Securities issued under our Green Finance Framework.

Solar Generation and Energy Storage Projects — In January 2022, we announced that, subject to approval by the CPUC, we would enter into a 15-year resource adequacy contract with PG&E to develop an additional 350 MW battery ESS at our Moss Landing Power Plant site. In September 2021, we announced the planned development, at a cost of approximately $550 million, of up to 300 MW of solar photovoltaic power generation facilities and up to 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois, based on the passage of Illinois Senate Bill 2408, the Energy Transition Act. In September 2020, we announced the planned development, at a cost of approximately $850 million, of up to 668 MW of solar photovoltaic power generation facilities and 260 MW of battery ESS in Texas. We will only invest in these growth projects if we are confident in the expected returns. See Note 3 to the Financial Statements for a summary of our solar and battery energy storage projects.

CO_2 Reductions — In September 2020 and December 2020, we announced our intention to retire (a) all of our remaining coal generation facilities in Illinois and Ohio, (b) one coal generation facility in Texas and (c) one natural gas facility in Illinois no later than year-end 2027 due to economic challenges, including incremental expenditures that would be required to comply with the CCR rule and ELG rule (see Note 13 to the Financial Statements), and in furtherance of our efforts to significantly reduce our carbon footprint. In April 2021, we announced we would retire the Joppa generation facilities by September 1, 2022, and in July 2021, we announced we would retire the Zimmer coal generation facility by May 31, 2022. See Note 4 to the Financial Statements for a summary of these planned generation retirements.

Moss Landing Outages

In September 2021, Moss Landing Phase I experienced an incident impacting a portion of the battery ESS. A review found that only a small, single digit-percentage of batteries at the facility were impacted and that the root cause originated in systems separate from the battery system. The facility will be offline as we perform the work necessary to return the facility to service. Moss Landing Phase II was not affected by this incident.

In February 2022, Moss Landing Phase II experienced an incident impacting a portion of the Battery ESS. An investigation is underway to determine the root cause of the incident. The facility will be offline as we perform the work necessary to return the facility to service. Moss Landing Phase I was not affected by the incident, but the facility will remain offline during the assessment stage of the Moss Landing Phase II incident.

We do not expect these incidents to have a material impact on our results of operations.

Mining Reclamation Award

In October 2021, the Office of Surface Mining Reclamation and Enforcement (OSM) announced Luminant as a recipient of its 2021 Excellence in Surface Coal Mining Reclamation Award for the work done to reclaim and restore previously mined land at its Monticello-Winfield Mine. The award recognizes companies that achieve the most exemplary coal mine reclamation in the nation. Luminant has a long history of environmental stewardship, reclaiming land long before being required under federal or state law.

COVID-19 Pandemic

With the global outbreak of the novel coronavirus (COVID-19) and the declaration of a pandemic by the World Health Organization on March 11, 2020, the U.S. government has deemed electricity generation, transmission and distribution as "critical infrastructure" providing essential services during this global emergency. As a provider of critical infrastructure, Vistra has an obligation to provide critically needed power to homes, businesses, hospitals and other customers. Vistra remains focused on protecting the health and well-being of its employees and the communities in which it operates while assuring the continuity of its business operations.

We have updated and implemented our company-wide pandemic plan to address specific aspects of the COVID-19 pandemic to guide our emergency response, business continuity, and the precautionary measures we are taking on behalf of employees and the public. We will continue to monitor developments affecting both our workforce and our customers, and we have taken, and will continue to take, health and safety measures that we determine are necessary in order to mitigate the impacts. To date, as a result of these business continuity measures, the Company has not experienced material disruptions in our operations due to COVID-19.

See Note 7 to the Financial Statements for a summary of certain tax-related impacts of the CARES Act to the Company.

The COVID-19 pandemic has presented potential new risks to the Company's business. Although there have been logistical and other challenges to date, there has been no material adverse impact on the Company's results of operations for the years ended December 31, 2021 and 2020. The situation surrounding COVID-19 remains fluid and the potential for a material impact on the Company's results of operations, financial condition and liquidity increases the longer the virus impacts the level of economic activity in the U.S. and globally. As a result, COVID-19 may have a range of impacts on the Company's operations, the full extent and scope of which are currently unknown. See Part I, Item 1A *Risk Factors — The outbreak of COVID-19, or the future outbreak of any other highly infectious or contagious diseases, could have a material and adverse effect on our business, financial condition, and results of operations*.

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.

Preferred Stock Offerings

On October 15, 2021, we issued 1,000,000 shares of Series A Preferred Stock in a private offering (Offering). The net proceeds of the Offering were approximately $990 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Offering to repurchase shares of our outstanding common stock under the Share Repurchase Program (discussed below).

On December 10, 2021, we issued 1,000,000 shares of Series B Preferred Stock in a private offering (Series B Offering) under our Green Finance Framework. The net proceeds of the Series B Offering were approximately $985 million, after deducting underwriting commissions and offering expenses. We intend to use the proceeds from the Series B Offering to pay for or reimburse existing and new eligible renewable and battery ESS developments.

See Note 14 to the Financial Statements for more information concerning the Series A Preferred Stock and the Series B Preferred Stock.

Share Repurchase Program

In October 2021, we announced that the Board had authorized a new share repurchase program (Share Repurchase Program) under which up to $2.0 billion of our outstanding common stock may be repurchased. The Share Repurchase Program became effective on October 11, 2021. The Share Repurchase Program supersedes the $1.5 million share repurchase program previously announced in September 2020 (2020 Share Repurchase Program). In the three months ended December 31, 2021, 19,330,365 shares of our common stock were repurchased under the Share Repurchase Program for approximately $409 million at an average price of $21.16 per share of common stock. As of December 31, 2021, approximately $1.591 billion was available for additional repurchases under the Share Repurchase Program. From January 1, 2022 through February 22, 2022, 16,059,290 shares of our common stock had been repurchased under the Share Repurchase Program for $355 million at an average price per share of common stock of $22.07, and at February 22, 2022, $1.236 billion was available for repurchase under the Share Repurchase Program. See Note 14 to the Financial Statements for more information concerning the Share Repurchase Program and the 2020 Share Repurchase 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. While the financial impacts resulting from Winter Storm Uri caused an increase in our consolidated net leverage, the Company remains committed to a strong balance sheet, and the anticipated securitization proceeds from ERCOT are expected to enable us to further execute this objective. See Note 1 to the Financial Statements for details of the securitization proceeds receivable from ERCOT, Note 11 to the Financial Statements for details of our long-term debt activity, and Note 10 to the Financial Statements for details of our accounts receivable financing.

Commodity-Linked Revolving Credit Facility

On February 4, 2022, Vistra Operations entered into a credit agreement by and among Vistra Operations, Vistra Intermediate, the lenders, joint lead arrangers and joint bookrunners party thereto, and Citibank, N.A., as administrative agent and collateral agent. The Credit Agreement provides for a $1.0 billion senior secured commodity-linked revolving credit facility (the Commodity-Linked Facility). Vistra Operations intends to use the liquidity provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes. See Note 11 to the Financial Statements for more information concerning the Commodity-Linked Facility.

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:

	2021-2022	2022-2023
	(average price per MW-day)	
RTO zone	$ 140.00	$ 50.00
ComEd zone	195.55	68.96
MAAC zone	140.00	95.79
EMAAC zone	165.73	97.86
ATSI zone	171.33	50.00
DEOK zone	140.00	71.69

Our capacity sales in PJM, net of purchases, aggregated by planning year and capacity type through planning year 2022-2023, are as follows:

	2021-2022		2022-2023	
	East Segment	Sunset Segment	East Segment	Sunset Segment
CP auction capacity sold, net (MW)	6,384	3,028	5,500	1,519
Bilateral capacity sold, net (MW)	200	50	200	—
Total segment capacity sold, net (MW)	6,584	3,078	5,700	1,519
Average price per MW-day	$ 159.18	$ 148.83	$ 68.54	$ 70.52

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:

	Winter 2021 - 2022	Summer 2022
Price per kW-month	$ 1.00	$ —

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 winter 2023-2024, are as follows:

	East Segment				
	Winter 2021 - 2022	Summer 2022	Winter 2022 - 2023	Summer 2023	Winter 2023 - 2024
Auction capacity sold (MW)	125	—	—	—	—
Bilateral capacity sold (MW)	1,017	565	212	104	38
Total capacity sold (MW)	1,142	565	212	104	38
Average price per kW-month	$ 0.94	$ 2.18	$ 1.31	$ 1.76	$ 1.78

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:

	2021-2022	2022-2023	2023-2024	2024-2025
Price per kW-month	$ 4.63	$ 3.80	$ 2.00	$ 2.61

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 through planning year 2025-2026.

	East Segment				
	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Auction capacity sold (MW)	3,037	2,996	3,091	2,967	—
Bilateral capacity sold (MW)	213	95	20	78	78
Total capacity sold (MW)	3,250	3,091	3,111	3,045	78
Average price per kW-month	$ 4.35	$ 3.92	$ 2.12	$ 3.18	$ 3.47

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

	2021-2022
Price per MW-day	$ 5.00

MISO capacity sales through planning year 2024-2025 are as follows:

	Sunset Segment			
	2021-2022	2022-2023	2023-2024	2024-2025
Bilateral capacity sold in MISO (MW)	3,012	1,075	569	265
Total MISO segment capacity sold (MW)	3,012	1,075	569	265
Average price per kW-month	$ 2.31	$ 1.94	$ 2.58	$ 4.26

CAISO — Our capacity sales in CAISO, aggregated by calendar year for 2022 through 2023 for Moss Landing, are as follows:

	West Segment	
	2022	2023
Bilateral capacity sold (Avg MW)	1,287	1,275

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 flows, 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 flows, 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.

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. 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.

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. When natural gas prices are 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 our Texas, East, West and Sunset segments as of December 31, 2021 were as follows:

	2022	2023
Nuclear/Renewable/Coal Generation:		
Texas	90 %	55 %
Sunset	98 %	47 %
Gas Generation:		
Texas	71 %	8 %
East	94 %	35 %
West	100 %	6 %

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 MMBtu/MWh) on realized pre-tax 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 at December 31, 2021.

	2022	2023
Texas:		
Nuclear/Renewable/Coal Generation: $2.50/MWh increase in power price	$ 13	$ 53
Nuclear/Renewable/Coal Generation: $2.50/MWh decrease in power price	$ (11)	$ (50)
Gas Generation: $1.00/MWh increase in spark spread	$ 13	$ 39
Gas Generation: $1.00/MWh decrease in spark spread	$ (12)	$ (37)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$ (6)	$ (18)
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$ 6	$ 10
East:		
Gas Generation: $1.00/MWh increase in spark spread	$ 4	$ 32
Gas Generation: $1.00/MWh decrease in spark spread	$ (2)	$ (30)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$ 1	$ (2)
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$ (1)	$ 2
West:		
Gas Generation: $1.00/MWh increase in spark spread	$ —	$ 4
Gas Generation: $1.00/MWh decrease in spark spread	$ —	$ (4)
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)	$ —
Sunset:		
Coal Generation: $2.50/MWh increase in power price	$ 2	$ 32
Coal Generation: $2.50/MWh decrease in power price	$ (1)	$ (28)

Competitive Retail Markets and Customer Retention

Competitive retail activity in ERCOT has resulted in retail customer churn as customers switch retail electricity providers for various reasons. Based on numbers of meters, our total retail customer counts increased approximately 3%, 1% and 2% in 2021, 2020 and 2019, respectively. Based upon December 31, 2021 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 $56 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, 2021, 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 2022 at December 31, 2021) 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, operations technology systems, supporting components, and/or associated sites utilized by the Company or one of our service providers could disrupt normal business operations and affect our ability to control our generation assets, access retail customer information and limit communication with third parties. Breaches and threats are becoming increasingly sophisticated, complex, change frequently and may be difficult to detect, and our increased use of remote work environments and virtual platforms in response to the COVID-19 pandemic may also increase our risk of cyber-attack or data security breaches. 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, significant liabilities, reputational damage, regulatory action, and disrupt business operations, which could 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 Federal Bureau of Investigation, Cybersecurity and Infrastructure Security Agency, U.S. Department of Homeland Security, Electricity Information Sharing and Analysis Center, U.S. Cyber Emergency Response Team, 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 marketplace 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 have controls in place designed to protect our infrastructure, provide our employees awareness training of cybersecurity threats, routinely utilize information technology security experts to assist us in our evaluations of the effectiveness of our information technology systems and controls, and we regularly enhance our security measures to protect our systems and data, including encryption, tokenization and authentication technologies to mitigate cybersecurity risks and increasing our monitoring capabilities to enhance early detection and rapid response to potential cyber threats. In response to the fact that a portion of our workforce continues to work remotely and within a hybrid work environment, we have reduced our attack surface process and technology, which removes remote network risk from our internal systems, assets, or data.

We also apply the knowledge gained through industry and government organizations, external partner cyber risk and maturity assessments 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 are impacted by extreme or sustained weather conditions and 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 have made, and may make such fluctuations more pronounced. 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 and Estimates

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.

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 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 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 files a U.S. federal income tax return that includes the results of its consolidated subsidiaries. Vistra is the corporate parent of the Vistra 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.

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 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 reflected the obligation associated with TRA Rights at fair value in the amount of $574 million as of the Effective Date related to these future payment obligations. As of December 31, 2021, the TRA obligation has been adjusted to $395 million. During the year ended December 31, 2021, we recorded a decrease to the carrying value of the TRA obligation totaling $115 million as a result of adjustments to forecasted taxable income, including the financial impacts of Winter Storm Uri, and anticipated tax benefits available under current tax laws for planned additional renewable development projects. As of December 31, 2021, expected undiscounted federal and state payments under the TRA is estimated to be approximately $1.4 billion. The TRA obligation value is the discounted amount of projected 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 22.9%;
- 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 Effective 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 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 our consolidated statements of operations.

For the next five years, Vistra is projected to spend approximately $265 million (on a nominal basis) to achieve its reclamation objectives. During the years ended December 31, 2020 and 2019, we transferred $15 million and $135 million, respectively, in ARO obligations to third parties 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.

As of December 31, 2021, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled \$1.635 billion and includes an assumption that Vistra 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 changes in estimates of the ARO do not impact Vistra's earnings.

See Note 21 to the Financial Statements for additional discussion of ARO obligations and adjustments made to the ARO obligation estimates during the years ended December 31, 2021, 2020 and 2019.

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. See Note 21 to the Financial Statements for discussion of impairments of long-lived assets recorded in the years ended December 31, 2021 and 2020.

Recoverability of long-lived assets is determined by a comparison of the carrying amount of the long-lived asset group to the net cash flows expected to be generated by the asset group, through considering specific assumptions for forward natural gas and electricity prices, forward capacity prices, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures, forecasted fuel prices and forecasted operating costs. The carrying value of such asset groups is determined to be unrecoverable if the projected undiscounted cash flows are less than the carrying value.

If an asset group carrying value is determined to be unrecoverable, fair value will be calculated based on a market participant view and a loss will be recorded for the amount the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows (income approach) and supported by available market valuations, if applicable. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, forward capacity prices, market heat rates, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures and forecasted fuel prices. Another key assumption in the income approach is the discount rate applied to the forecasted cash flows. 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 trade names of TXU Energy™, Ambit Energy, 4Change Energy™, Homefield, Dynegy Energy Services, TriEagle Energy, Public Power and U.S. Gas & Electric, respectively, are required to be evaluated for impairment at least annually (we have selected October 1 as our annual goodwill 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 Retail and Texas Generation reporting units exceeded their carrying value at October 1, 2021. 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, 2021, $2.461 billion of our goodwill was allocated to our Retail reporting unit and $122 million was allocated to our Texas Generation reporting unit. 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 excess carrying value is written off as an impairment charge.

The determination of enterprise value of a reporting unit 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 Consolidated Financial Results — Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

	Year Ended December 31, 2021	Year Ended December 31, 2020	Favorable (Unfavorable) $ Change
Operating revenues	$ 12,077	$ 11,443	$ 634
Fuel, purchased power costs and delivery fees	(9,169)	(5,174)	(3,995)
Operating costs	(1,559)	(1,622)	63
Depreciation and amortization	(1,753)	(1,737)	(16)
Selling, general and administrative expenses	(1,040)	(1,035)	(5)
Impairment of long-lived and other assets	(71)	(356)	285
Operating income (loss)	(1,515)	1,519	(3,034)
Other income	140	34	106
Other deductions	(16)	(42)	26
Interest expense and related charges	(384)	(630)	246
Impacts of Tax Receivable Agreement	53	5	48
Equity in earnings of unconsolidated investment	—	4	(4)
Income (loss) before income taxes	(1,722)	890	(2,612)
Income tax (expense) benefit	458	(266)	724
Net income (loss)	$ (1,264)	$ 624	$ (1,888)

	Year Ended December 31, 2021							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Operating revenues	$ 7,871	$ 2,790	$ 2,587	$ 374	$ 739	$ —	$ (2,284)	$ 12,077
Fuel, purchased power costs and delivery fees	(4,568)	(3,991)	(2,123)	(253)	(518)	—	2,284	(9,169)
Operating costs	(127)	(704)	(243)	(37)	(417)	(30)	(1)	(1,559)
Depreciation and amortization	(212)	(608)	(698)	(60)	(139)	—	(36)	(1,753)
Selling, general and administrative expenses	(718)	(88)	(75)	(32)	(55)	(26)	(46)	(1,040)
Impairment of long-lived and other assets	(33)	—	—	—	(38)	—	—	(71)
Operating income (loss)	2,213	(2,601)	(552)	(8)	(428)	(56)	(83)	(1,515)
Other income	1	84	—	—	15	35	5	140
Other deductions	(7)	(9)	—	—	2	—	(2)	(16)
Interest expense and related charges	(9)	14	(15)	9	(2)	(1)	(380)	(384)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	53	53
Income (loss) before income taxes	2,198	(2,512)	(567)	1	(413)	(22)	(407)	(1,722)
Income tax benefit (expense)	(2)	—	—	—	—	—	460	458
Net income (loss)	$ 2,196	$ (2,512)	$ (567)	$ 1	$ (413)	$ (22)	$ 53	$ (1,264)

	Year Ended December 31, 2020							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Operating revenues	$ 8,270	$ 4,116	$ 2,415	$ 282	$ 1,252	$ 3	$ (4,895)	$ 11,443
Fuel, purchased power costs and delivery fees	(6,857)	(1,078)	(1,262)	(168)	(704)	—	4,895	(5,174)
Operating costs	(123)	(727)	(270)	(30)	(408)	(63)	(1)	(1,622)
Depreciation and amortization	(303)	(475)	(721)	(19)	(133)	(22)	(64)	(1,737)
Selling, general and administrative expenses	(675)	(75)	(89)	(26)	(71)	(27)	(72)	(1,035)
Impairment of long-lived assets and other assets	—	—	—	—	(356)	—	—	(356)
Operating income (loss)	312	1,761	73	39	(420)	(109)	(137)	1,519
Other income	6	3	1	1	6	10	7	34
Other deductions	1	(12)	(30)	—	2	(2)	(1)	(42)
Interest expense and related charges	(10)	8	(7)	10	(2)	—	(629)	(630)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	5	5
Equity in earnings of unconsolidated investment	—	—	4	—	—	—	—	4
Income (loss) before income taxes	309	1,760	41	50	(414)	(101)	(755)	890
Income tax expense	—	—	—	—	—	—	(266)	(266)
Net income (loss)	$ 309	$ 1,760	$ 41	$ 50	$ (414)	$ (101)	$ (1,021)	$ 624

In February 2021, Winter Storm Uri resulted in a $2.2 billion negative impact on the Company's pre-tax earnings in the year ended December 31, 2021, after taking into account approximately $544 million in securitization proceeds Vistra expects to receive from ERCOT as further described in Note 1 to the Financial Statements. For the remainder of 2021, our operating segments delivered strong operating performance with a disciplined focus on cost management and self-help activities while generating and selling essential electricity in a safe and reliable manner.

Consolidated results decreased $3.034 billion to a net operating loss of $1.515 billion in the year ended December 31, 2021 compared to the year ended December 31, 2020. The change in results was driven by the Winter Storm Uri impacts, including the need to procure power in ERCOT at market prices at or near the price cap due to lower output from our natural gas-fueled power plants driven by natural gas deliverability issues and our coal-fueled power plants driven by coal fuel handling challenges, high fuel costs, and high retail load costs including ancillary service costs and reliability deployment price adders. Results were adversely impacted by $759 million in pre-tax unrealized losses on commodity hedging transactions in 2021 compared to $231 million in pre-tax unrealized gains on commodity hedging transactions in 2020. Power, natural gas and coal forward market curves moved up during the year ended December 31, 2021, driving these net pre-tax unrealized losses on commodity hedging transactions.

Operating costs decreased $63 million to $1.559 billion in the year ended December 31, 2021 compared to the year ended December 31, 2020 primarily driven by lower LTSA costs and lower property taxes.

Interest expense and related charges decreased $246 million to $384 million in the year ended December 31, 2021 compared to the year ended December 31, 2020 driven by $134 million in unrealized mark-to-market gains on interest rate swaps in 2021 compared to $155 million in unrealized mark-to-market losses on interest rate swaps in 2020. See Note 21 to the Financial Statements.

For the years ended December 31, 2021 and 2020, the impacts of the TRA totaled income of $53 million and $5 million, respectively. See Note 8 to the Financial Statements for discussion of the impacts of the TRA obligation.

For the year ended December 31, 2021, income tax benefit totaled $458 million and the effective tax rate was 26.6%. For the year ended December 31, 2020, income tax benefit totaled $266 million and the effective tax rate was 29.9%. See Note 7 to the Financial Statements for reconciliation of the effective rates to the U.S. federal statutory rate.

Consolidated cash flows used in operations totaled $206 million for the year ended December 31, 2021 compared to consolidated cash flows provided by operations of $3.337 billion for the year ended December 31, 2020. The unfavorable change of $3.543 billion was primarily driven by lower cash from operations due to Winter Storm Uri impacts and higher cash margin deposits posted with third-parties. Cash margin deposits posted were driven by net pre-tax unrealized losses on commodity hedging transactions reflecting power, natural gas and coal forward market curves that moved up during the year ended December 31, 2021.

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 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, 2021 Compared to Year Ended December 31, 2020

	Year Ended December 31,		Favorable (Unfavorable) $ Change
	2021	2020	
Net income (loss)	$ (1,264)	$ 624	$ (1,888)
Income tax expense (benefit)	(458)	266	(724)
Interest expense and related charges (a)	384	630	(246)
Depreciation and amortization (b)	1,831	1,812	19
EBITDA	493	3,332	(2,839)
Unrealized net (gain) loss resulting from commodity hedging transactions	759	(231)	990
Generation plant retirement expenses	18	43	(25)
Fresh start/purchase accounting impacts	(138)	38	(176)
Impacts of Tax Receivable Agreement	(53)	(5)	(48)
Non-cash compensation expenses	51	63	(12)
Transition and merger expenses	(8)	16	(24)
Other, including impairment of long-lived and other assets	80	375	(295)
Loss on disposal of investment in NELP	—	29	(29)
COVID-19-related expenses (c)	8	25	(17)
Winter Storm Uri impacts (d)	698	—	698
Adjusted EBITDA	$ 1,908	$ 3,685	$ (1,777)

(a) Includes unrealized mark-to-market net gains on interest rate swaps of $134 million and unrealized mark-to-market net losses on interest rate swaps of $155 million for the years ended December 31, 2021 and 2020, respectively.
(b) Includes nuclear fuel amortization in the Texas segment of $78 million and $75 million for the years ended December 31, 2021 and 2020, respectively.
(c) Includes material and supplies and other incremental costs related to our COVID-19 response.
(d) For the year ending December 31, 2021, includes the following of the Winter Storm Uri impacts, which we believe are not reflective of our operating performance: allocation of ERCOT default uplift charges which are expected to be paid over more than 90 years under current protocols; accrual of Koch earn-out amounts that the Company will pay by the end of the second quarter of 2022; future bill credits related to Winter Storm Uri (as further described below); and Winter Storm Uri related legal fees and other costs. The adjustment for future bill credits relates to large commercial and industrial customers that curtailed their usage during Winter Storm Uri and will reverse and impact Adjusted EBITDA in future periods as the credits are applied to customer bills. We estimate the amounts to be applied in future periods are 2022 (approximately $150 million), 2023 (approximately $67 million), 2024 (approximately $11 million) and 2025 (approximately $4 million). The Company believes the inclusion of the bill credits as a reduction to Adjusted EBITDA in the years in which such bill credits are applied more accurately reflects its operating performance.

	Year Ended December 31, 2021							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Net income (loss)	$2,196	$ (2,512)	$ (567)	$ 1	$ (413)	$ (22)	$ 53	$ (1,264)
Income tax expense (benefit)	2	—	—	—	—	—	(460)	(458)
Interest expense and related charges (a)	9	(14)	15	(9)	2	1	380	384
Depreciation and amortization (b)	212	686	698	60	139	—	36	1,831
EBITDA	2,419	(1,840)	146	52	(272)	(21)	9	493
Unrealized net (gain) loss resulting from commodity hedging transactions	(1,403)	1,139	655	38	330	—	—	759
Generation plant retirement expenses	—	—	—	—	18	—	—	18
Fresh start/purchase accounting impacts	2	(14)	(74)	—	(52)	—	—	(138)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	(53)	(53)
Non-cash compensation expenses	—	—	—	—	—	—	51	51
Transition and merger expenses	(2)	—	—	—	—	(15)	9	(8)
Other, including impairment of long-lived and other assets	57	18	9	3	33	3	(43)	80
COVID-19-related expenses (c)	—	4	1	—	2	—	1	8
Winter Storm Uri impacts (d)	239	457	—	—	1	—	1	698
Adjusted EBITDA	$1,312	$ (236)	$ 737	$ 93	$ 60	$ (33)	$ (25)	$ 1,908

(a) Includes $134 million of unrealized mark-to-market net gains on interest rate swaps.
(b) Includes nuclear fuel amortization of $78 million in the Texas segment.
(c) Includes material and supplies and other incremental costs related to our COVID-19 response.
(d) Includes the following of the Winter Storm Uri impacts, which we believe are not reflective of our operating performance: allocation of ERCOT default uplift charges which are expected to be paid over more than 90 years under current protocols; accrual of Koch earn-out amounts that the Company will pay by the end of the second quarter of 2022; future bill credits related to Winter Storm Uri (as further described below); and Winter Storm Uri related legal fees and other costs. The adjustment for future bill credits relates to large commercial and industrial customers that curtailed their usage during Winter Storm Uri and will reverse and impact Adjusted EBITDA in future periods as the credits are applied to customer bills. We estimate the amounts to be applied in future periods are 2022 (approximately $150 million), 2023 (approximately $67 million), 2024 (approximately $11 million) and 2025 (approximately $4 million). The Company believes the inclusion of the bill credits as a reduction to Adjusted EBITDA in the years in which such bill credits are applied more accurately reflects its operating performance.

	Year Ended December 31, 2020							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Net income (loss)	$ 309	$1,760	$ 41	$ 50	$ (414)	$ (101)	$ (1,021)	$ 624
Income tax expense	—	—	—	—	—	—	266	266
Interest expense and related charges (a)	10	(8)	7	(10)	2	—	629	630
Depreciation and amortization (b)	303	550	721	19	133	22	64	1,812
EBITDA	622	2,302	769	59	(279)	(79)	(62)	3,332
Unrealized net (gain) loss resulting from commodity hedging transactions	340	(691)	15	10	95	—	—	(231)
Generation plant retirement expenses	—	—	—	—	43	—	—	43
Fresh start/purchase accounting impacts	5	(8)	22	—	19	—	—	38
Impacts of Tax Receivable Agreement	—	—	—	—	—	—	(5)	(5)
Non-cash compensation expenses	—	—	—	—	—	—	63	63
Transition and merger expenses	5	2	1	—	—	(3)	11	16
Other, including impairment of long-lived and other assets	11	26	10	4	359	1	(36)	375
Loss on disposal of investment in NELP	—	—	29	—	—	—	—	29
COVID-19-related expenses (c)	—	15	3	—	5	—	2	25
Adjusted EBITDA	$ 983	$1,646	$ 849	$ 73	$ 242	$ (81)	$ (27)	$ 3,685

(a) Includes $155 million of unrealized mark-to-market net losses on interest rate swaps.
(b) Includes nuclear fuel amortization of $75 million in the Texas segment.
(c) Includes material and supplies and other incremental costs related to our COVID-19 response.

Retail Segment — Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

	Year Ended December 31, 2021	Year Ended December 31, 2020	Favorable (Unfavorable) Change
Operating revenues:			
Revenues in ERCOT	$ 5,943	$ 5,880	$ 63
Revenues in Northeast/Midwest	2,255	2,406	(151)
Amortization expense	(2)	(5)	3
Unrealized net losses on hedging activities (a)	(325)	(11)	(314)
Total operating revenues	$ 7,871	$ 8,270	$ (399)
Fuel, purchased power costs and delivery fees:			
Purchases from affiliates	(4,002)	(4,566)	564
Unrealized net gains (losses) on hedging activities with affiliates	1,719	(329)	2,048
Unrealized net gains on hedging activities	9	—	9
Delivery fees	(1,937)	(1,893)	(44)
Other costs (b)	(357)	(69)	(288)
Total fuel, purchased power costs and delivery fees	$ (4,568)	$ (6,857)	$ 2,289
Net income	**$ 2,196**	**$ 309**	**$ 1,887**
Adjusted EBITDA	**$ 1,312**	**$ 983**	**$ 329**
Retail sales volumes (GWh):			
Retail electricity sales volumes:			
Sales volumes in ERCOT	57,033	54,075	2,958
Sales volumes in Northeast/Midwest	36,070	36,274	(204)
Total retail electricity sales volumes	93,103	90,349	2,754
Weather (North Texas average) - percent of normal (c):			
Cooling degree days	90.0 %	90.0 %	
Heating degree days	92.0 %	91.0 %	

(a) For the year ended December 31, 2021, a net loss of $298 million was recognized in operating revenues due to the third quarter 2021 discontinuance of normal purchase and sale accounting on a retail electric contract portfolio where physical settlement is no longer considered probable throughout the contract term.

(b) For the year ended December 31, 2021, includes $153 million of future bill credits to large commercial and industrial customers.

(c) Weather data is obtained from Weatherbank, Inc. For the year ended December 31, 2021, normal is defined as the average over the 10-year period from December 2011 to December 2020. For the year ended December 31, 2020, normal is defined as the average over the 10-year period from December 2010 to December 2019.

The following table presents changes in net income (loss) and Adjusted EBITDA for the year ended December 31, 2021 compared to the year ended December 31, 2020.

		Year Ended December 31, 2021 Compared to 2020
Winter Storm Uri, including securitization proceeds receivable from ERCOT and bill credits	$	(75)
Monetization of certain commercial positions		207
Higher margins		228
Other driven by higher SG&A expense		(31)
Change in Adjusted EBITDA	**$**	**329**
Favorable impact of higher unrealized net gains on commodity hedging activities		1,743
Future bill credits and other costs related to Winter Storm Uri		(245)
Decrease in depreciation and amortization expenses		91
Other, including impairment of long-lived and other assets		(31)
Change in Net income	**$**	**1,887**

Generation — Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

	Year Ended December 31,							
	Texas		East		West		Sunset	
	2021	2020	2021	2020	2021	2020	2021	2020
Operating revenues:								
Electricity sales	$ 1,999	$ 896	$1,619	$ 833	$ 410	$ 289	$ 819	$ 883
Capacity revenue from ISO/RTO	—	—	(22)	(52)	1	—	184	164
Sales to affiliates	2,063	2,543	1,553	1,655	5	3	382	365
Rolloff of unrealized net gains (losses) representing positions settled in the current period	(207)	2	(159)	159	62	(22)	241	(205)
Unrealized net gains (losses) on hedging activities	(37)	217	51	(121)	(104)	12	(713)	133
Unrealized net gains (losses) on hedging activities with affiliates	(1,028)	458	(529)	(61)	—	—	(162)	(68)
Other revenues	—	—	74	2	—	—	(12)	(20)
Operating revenues	2,790	4,116	2,587	2,415	374	282	739	1,252
Fuel, purchased power costs and delivery fees:								
Fuel for generation facilities and purchased power costs	(2,829)	(960)	(2,072)	(1,225)	(251)	(166)	(810)	(744)
Fuel for generation facilities and purchased power costs from affiliates	—	6	2	(8)	—	—	(4)	2
Unrealized (gains) losses from hedging activities	133	14	(18)	8	4	—	304	45
Ancillary and other costs	(1,295)	(138)	(35)	(37)	(6)	(2)	(8)	(7)
Fuel, purchased power costs and delivery fees	(3,991)	(1,078)	(2,123)	(1,262)	(253)	(168)	(518)	(704)
Net income (loss)	**$(2,512)**	**$1,760**	**$ (567)**	**$ 41**	**$ 1**	**$ 50**	**$ (413)**	**$ (414)**
Adjusted EBITDA	**$ (236)**	**$1,646**	**$ 737**	**$ 849**	**$ 93**	**$ 73**	**$ 60**	**$ 242**
Production volumes (GWh):								
Natural gas facilities	30,921	35,093	55,428	55,938	5,365	5,284		
Lignite and coal facilities	25,513	26,013					36,953	29,971
Nuclear facilities	19,402	19,480						
Solar/Battery facilities	454	432			4			
Capacity factors:								
CCGT facilities	43.2 %	49.2 %	57.6 %	57.9 %	60.0 %	59.1 %		
Lignite and coal facilities	75.6 %	77.1 %					58.0 %	47.1 %
Nuclear facilities	96.3 %	96.7 %						
Weather - percent of normal (a):								
Cooling degree days	94 %	98 %	108 %	105 %	90 %	130 %	115 %	102 %
Heating degree days	94 %	85 %	93 %	92 %	111 %	95 %	90 %	89 %

(a) Reflects cooling degree days or heating degree days for the region based on Weather Services International (WSI) data.

	Year Ended December 31, 2021	Year Ended December 31, 2020
Market pricing		
Average ERCOT North power price ($/MWh)	$ 149.57	$ 21.46
Average NYMEX Henry Hub natural gas price ($/MMBtu)	$ 3.82	$ 1.99
Average natural gas price (a):		
TetcoM3 ($/MMBtu)	$ 3.40	$ 1.59
Algonquin Citygates ($/MMBtu)	$ 4.51	$ 2.00

	Year Ended December 31, 2021	Year Ended December 31, 2020
Average Market On-Peak Power Prices ($MWh) (b):		
PJM West Hub	$ 45.62	$ 24.55
AEP Dayton Hub	$ 44.88	$ 24.49
NYISO Zone C	$ 35.59	$ 19.37
Massachusetts Hub	$ 51.81	$ 26.57
Indiana Hub	$ 48.62	$ 26.77
Northern Illinois Hub	$ 41.15	$ 22.47

(a) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.
(b) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.

The following table presents changes in net income (loss) and Adjusted EBITDA for the year ended December 31, 2021 compared to the year ended December 31, 2020.

	Year Ended December 31, 2021 Compared to 2020			
	Texas	East	West	Sunset
Favorable/(unfavorable) change in revenue net of fuel	$ (447)	$ (175)	$ 34	$ (178)
Winter Storm Uri impact	(1,535)	50	—	17
Favorable/(unfavorable) change in other operating costs	19	8	(7)	(39)
Favorable/(unfavorable) change in selling, general and administrative expenses	—	10	(6)	8
Other (including other income and other deductions) (a)	81	(5)	(1)	10
Change in Adjusted EBITDA	**$ (1,882)**	**$ (112)**	**$ 20**	**$ (182)**
Favorable/(unfavorable) change in depreciation and amortization	(136)	23	(41)	(6)
Change in unrealized net losses on hedging activities	(1,830)	(640)	(28)	(235)
Other, including impairment of long-lived and other assets	25	(5)	—	329
Generation plant retirement expenses	—	—	—	25
Fresh start/purchase accounting impacts	6	96	—	71
Transition and merger expenses	2	1	—	—
Winter Storm Uri impact (ERCOT default uplift and legal disputes)	(457)	—	—	(1)
Loss on disposal of investment in NELP	—	29	—	—
Change in Net income (loss)	**$ (4,272)**	**$ (608)**	**$ (49)**	**$ 1**

(a) For the year ended December 31, 2021, includes insurance proceeds of $80 million in the Texas segment and $7 million in the Sunset segment.

The change in Texas segment results was primarily driven by the Winter Storm Uri impacts, including the need to procure power in ERCOT at market prices at or near the price cap due to lower output from our natural gas-fueled power plants driven by natural gas deliverability issues, lower margins from our natural gas-fueled power plants due to extremely high fuel costs, and, to a lesser extent, operational challenges associated with Winter Storm Uri, and unrealized hedging losses in the year ended December 31, 2021 versus unrealized hedging gains in the year ended December 31, 2020, partially offset by insurance proceeds received in 2021.

The change in East segment results was driven by lower revenue net of fuel and larger unrealized hedging losses in the year ended December 31, 2021 versus the year ended December 31, 2020, partially offset by loss on disposal of equity method investment in NELP for 100% ownership of NJEA (see Note 21 to the Financial Statements) in 2020.

The change in West segment results was driven by larger unrealized hedging losses in year ended December 31, 2021 versus the year ended December 31, 2020, partially offset by higher realized prices through hedging activities and plant optimization efforts.

The change in Sunset segment results was driven by larger unrealized hedging losses in year ended December 31, 2021 versus the year ended December 31, 2020 and lower margins due to lower realized prices and higher operating costs, partially offset by higher impairment of long-lived assets generation plant retirement expenses related to our Joppa/EEI, Kincaid and Zimmer coal generation facilities in 2020.

Asset Closure Segment — Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

	Year Ended December 31, 2021	Year Ended December 31, 2020	Favorable (Unfavorable) Change
Operating revenues	$ —	$ 3	$ (3)
Operating costs	(30)	(63)	33
Depreciation and amortization	—	(22)	22
Selling, general and administrative expenses	(26)	(27)	1
Operating loss	(56)	(109)	53
Other income	35	10	25
Other deductions	—	(2)	2
Interest expense and related charges	(1)	—	(1)
Income (loss) before income taxes	(22)	(101)	79
Net loss	**$ (22)**	**$ (101)**	**$ 79**
Adjusted EBITDA	**$ (33)**	**$ (81)**	**$ 48**

Operating costs for the years ended December 31, 2021 and 2020 included ongoing costs associated with the decommissioning and reclamation of retired plants and mines. The year ended December 31, 2021 includes a gain on the settlement of rail transportation disputes (see Note 21 to the Financial Statements).

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, 2021 and 2020. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $759 million in unrealized net losses and $231 million in unrealized net gains for the years ended December 31, 2021 and 2020, respectively, arising from mark-to-market accounting for positions in the commodity contract portfolio.

	Year Ended December 31, 2021	Year Ended December 31, 2020
Commodity contract net liability at beginning of period	$ (75)	$ (279)
Settlements/termination of positions (a)	(295)	(14)
Changes in fair value of positions in the portfolio (b)	(464)	245
Other activity (c)	(32)	(27)
Commodity contract net liability at end of period	$ (866)	$ (75)

(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, 2021 and 2020 also include reversals of $3 million and $12 million, respectively, of previously recorded unrealized losses related to commodity contracts acquired in the Merger, Crius Transaction and Ambit Transaction. The year ended December 31, 2020 includes reversals of $1 million of previously recorded unrealized losses related to Vistra beginning balances. 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) 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, 2021, 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, 2021				
Source of fair value	**Less than 1 year**	**1-3 years**	**4-5 years**	**Excess of 5 years**	**Total**
Prices actively quoted	$ (631)	$ (116)	$ 2	$ —	$ (745)
Prices provided by other external sources	352	(113)	1	(1)	239
Prices based on models	(72)	(83)	(108)	(97)	(360)
Total	$ (351)	$ (312)	$ (105)	$ (98)	$ (866)

FINANCIAL CONDITION

Operating Cash Flows

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020 — Cash used in operating activities totaled $206 million in the year ended December 31, 2021 compared to cash provided by operating activities of $3.337 billion in the year ended December 31, 2020. The unfavorable change of $3.543 billion was primarily driven by lower cash from operations due to Winter Storm Uri impacts and higher cash margin deposits posted with third-parties. Cash margin deposits posted were driven by net pre-tax unrealized losses on commodity hedging transactions reflecting power, natural gas and coal forward market curves that moved up during the year ended December 31, 2021.

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 $297 million, $311 million and $236 million for the year ended December 31, 2021, 2020 and 2019, 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, 2021 Compared to Year Ended December 31, 2020 — Cash used in investing activities totaled $1.153 billion and $1.572 billion in the years ended December 31, 2021 and 2020, respectively. Capital expenditures totaled $1.033 billion and $1,259 million in the years ended December 31, 2021 and 2020, respectively, and. consisted of the following:

	Year Ended December 31,	
	2021	**2020**
Capital expenditures, including LTSA prepayments	$ 549	$ 770
Nuclear fuel purchases	44	88
Growth and development expenditures	440	401
Capital expenditures	1,033	$ 1,259

Cash used in investing activities in the year ended December 31, 2021 and 2020 also reflected net purchases of environmental allowances of $213 million and $339 million, respectively. In the year ended December 31, 2021 and 2020, we received insurance proceeds of $89 million and $35 million, respectively.

Financing Cash Flows

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020 — Cash provided by financing activities totaled $2.274 billion in the year ended December 31, 2021 and cash used in financing activities totaled $1.796 billion in the year ended December 31, 2020. The change was primarily driven by:

- proceeds of $1.975 billion from the issuance of preferred stock in 2021;
- the issuance of $1.250 billion principal amount of Vistra Operations senior unsecured notes in 2021;
- $500 million in cash received from the sale of a portion of the PJM capacity that cleared for Planning Years 2021-2022 in 2021;
- redemption of $747 million principal amount of outstanding of Vistra unsecured senior notes in 2020;
- net repayment of $350 million in short-term borrowings under the Revolving Credit Facility in 2020; and
- repayment of $100 million of term loans under the Vistra Operations Credit Facilities in 2020;

partially offset by:

- $471 million in cash paid for share repurchases in 2021; and
- net repayments of $300 million under the Receivables Facility in 2021 compared to net repayments of $150 million in 2020.

Debt Activity

See Note 10 to the Financial Statements for details of the Receivables Facility and Repurchase Facility and 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, 2021:

	December 31, 2021	December 31, 2020	Change
Cash and cash equivalents	$ 1,325	$ 406	$ 919
Vistra Operations Credit Facilities — Revolving Credit Facility	1,254	1,988	(734)
Vistra Operations — Alternate Letter of Credit Facility	—	5	(5)
Total available liquidity (a)	$ 2,579	$ 2,399	$ 180

(a) Excludes amounts available to be borrowed under the Receivables Facility and the Repurchase Facility, respectively. See Note 10 to the Financial Statements for detail on our accounts receivable financing.

The $180 million increase in available liquidity for the year ended December 31, 2021 was primarily driven by proceeds of $1.975 billion from the issuance of preferred stock in 2021, cash received from the issuance of $1.250 billion principal amount of Vistra Operations senior unsecured notes in May 2021 and $500 million in cash received from the sale of a portion of the PJM capacity that cleared for Planning Years 2021-2022, partially offset by cash used in operations, including higher cash margin deposits posted with third parties, $1.033 billion of capital expenditures (including LTSA prepayments, nuclear fuel and development and growth expenditures), a $734 increase in letters of credit outstanding under the Revolving Credit Facility, $290 million in dividends paid to stockholders, $471 million in cash paid for share repurchases, $300 million in net cash repayments under the accounts receivable financing facilities and the maturity of a $250 million Alternate LOC Facility. Additionally, in February 2022, we entered into a $1.0 billion senior secured commodity-linked revolving credit facility (the Commodity-Linked Facility) (see Note 11 to the Financial Statements).

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

If the Company experienced a significant reduction in revenues or increases in costs or collateral requirements, such as a result of Winter Storm Uri, the Company believes it would have additional alternatives to maintain access to liquidity, including drawing upon available liquidity, accessing additional sources of capital or reducing capital expenditures, planned voluntary debt repayments or operating costs.

The maturities of our long-term debt are relatively modest until 2023. Interest payments on long-term debt are expected to total approximately $499 million in 2022, $946 million in 2023-2024, $753 million in 2025-2026 and $372 million thereafter. See Note 11 to the Financial Statements for details of our long-term debt maturities.

Our obligations under commodity purchase and services agreements, including capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear-related outsourcing and other purchase commitments, are expected to total approximately $1.850 billion in 2022, $1.250 billion in 2023-2024, $700 million in 2025-2026 and $585 million thereafter. See Note 12 to the Financial Statements for maturities of lease liabilities and Note 13 to the Financial Statements for commitments related to long-term service and maintenance contracts.

Capital Expenditures

Estimated 2022 capital expenditures and nuclear fuel purchases as of November 5, 2021 total approximately $1.814 billion and include:

- $1.002 billion for solar and energy storage development;
- $570 million for investments in generation and mining facilities;
- $117 million for nuclear fuel purchases;
- $72 million for information technology and other corporate investments; and
- $53 million for other growth 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.

As of December 31, 2021, we received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $1.263 billion in cash has been posted with counterparties as compared to $257 million posted at December 31, 2020;
- $39 million in cash has been received from counterparties as compared to $33 million received at December 31, 2020;
- $1.558 billion in letters of credit have been posted with counterparties as compared to $878 million posted at December 31, 2020; and
- $35 million in letters of credit have been received from counterparties as compared to $18 million received at December 31, 2020.

See *Collateral Support Obligations* below for information related to collateral posted in accordance with the PUCT and ISO/RTO rules.

Income Tax Payments

In the next 12 months, we do not expect to make federal income tax payments due to Vistra's loss position in 2021 and use of NOL carryforwards. We expect to make approximately $35 million in state income tax payments, offset by $11 million in state tax refunds, and less than $1 million in TRA payments in the next 12 months.

For the year ended December 31, 2021, there were no federal income tax payments, $52 million in state income tax payments, $2 million in state income tax refunds and $2 million in TRA payments.

Capitalization

Our capitalization ratios consisted of 56% and 52% long-term debt (less amounts due currently) and 44% and 48% stockholders' equity at December 31, 2021 and 2020, respectively. Total long-term debt (including amounts due currently) to capitalization was 56% and 53% at December 31, 2021 and 2020, 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, 2021, 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, 2021, Vistra has posted letters of credit in the amount of $74 million with the PUCT, which is subject to adjustments.

The ISOs/RTOs we operate in have rules in place to assure adequate creditworthiness of parties that participate in the markets operated by those ISOs/RTOs. Under these rules, Vistra has posted collateral support totaling $420 million in the form of letters of credit, $20 million in the form of a surety bond and $1 million of cash at December 31, 2021 (which is subject to daily adjustments based on settlement activity with the ISOs/RTOs).

Material Cross-Default/Acceleration Provisions

Certain of our contractual arrangements contain provisions that could result in an event of default if there were 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 under such facilities, which totaled approximately $2.54 billion at December 31, 2021.

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 the Vistra Operations Senior Unsecured Indentures and the Vistra Operations 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 may result in a cross default under the Vistra Operations Senior Unsecured Notes, the Senior Secured 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 TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands and TriEagle, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), 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 or any of the other Originators, in a principal amount of at least $50 million, after the expiration of any applicable grace period, 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.

The Repurchase Facility contains a cross-default provision. The cross-default provision applies, among other instances, if an event of default (or similar event) occurs under the Receivables Facility or the Vistra Operations Credit Facilities. If this cross-default provision is triggered, a termination event under the Repurchase Facility would occur and the Repurchase 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.

Under the Secured 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 Secured LOC Facilities.

Under the Commodity-Linked Facility, 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 Commodity-Linked Facility.

Guarantees

See Note 13 to the Financial Statements for discussion of guarantees.

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

Risk Oversight

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

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

Commodity Price Risk

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

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

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

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

VaR for Underlying Generation Assets and Energy-Related Contracts — This measurement estimates the potential loss in value, due to changes in market conditions, of all underlying generation assets and contracts, based on a 95% confidence level and an assumed holding period of 60 days. The forward period covered by this calculation includes the current and subsequent calendar year at the time of calculation.

	Year Ended December 31,	
	2021	2020
Month-end average VaR	$ 424	$ 234
Month-end high VaR	$ 684	$ 361
Month-end low VaR	$ 222	$ 164

The VaR risk measures in 2021 were primarily comparable to the prior year. The increase in month-end high VaR risk measure in 2021 is driven by a larger net open position, higher forward prices and an increase in market implied volatility as compared to the prior year.

Interest Rate Risk

The following table provides information concerning our financial instruments at December 31, 2021 and 2020 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						2021 Total Carrying Amount	2021 Total Fair Value	2020 Total Carrying Amount	2020 Total Fair Value
	2022	2023	2024	2025	2026	There-after				
Long-term debt, including current maturities (a):										
Variable rate debt amount	$ 29	$ 28	$ 29	$2,457	$ —	$ —	$2,543	$ 2,518	$2,572	$ 2,565
Average interest rate (b)	1.85 %	1.85 %	1.85 %	1.85 %	— %	— %	1.85 %		1.90 %	
Debt swapped to fixed (c):										
Notional amount	$ —	$2,300	$ —	$ —	$2,300	$ —	$4,600		$4,600	
Average pay rate	3.77 %	4.10 %	4.75 %	4.77 %	4.77 %	— %				
Average receive rate	1.86 %	2.24 %	2.98 %	3.01 %	3.01 %	— %				

____

(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, 2021.
(c) Interest rate swaps have maturity dates through July 2026. Excludes $2.12 billion of debt swapped to variable that is matched against the terms of $2.12 billion of debt swapped to fixed that effectively fix the out-of-the-money position of such swaps (see Note 11 to the Financial Statements).

As of December 31, 2021, 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 $2 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.

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 $2.357 billion at December 31, 2021.

As of December 31, 2021, Retail segment credit exposure totaled approximately $900 million of primarily trade accounts receivable. Cash deposits and letters of credit held as collateral for these receivables totaled $60 million, resulting in a net exposure of $840 million. 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.

As of December 31, 2021, aggregate Texas, East and Sunset segments credit exposure totaled $1.457 billion including $687 million related to derivative assets and $770 million of accounts receivable, after taking into account master netting agreement provisions but excluding collateral impacts.

Including collateral posted to us by counterparties, our net Texas, East and Sunset segments exposure was $1.390 billion, as seen in the following table that presents the distribution of credit exposure by counterparty credit quality at December 31, 2021. 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	$ 947	$ 24	$ 923
Below investment grade or no rating	510	43	467
Totals	$ 1,457	$ 67	$ 1,390

Significant (*i.e.*, 10% or greater) concentration of credit exposure exists with one counterparty, which represented an aggregate $619 million, or 45%, of the total net exposure. We view exposure to this counterparty to be within an acceptable level of risk tolerance due to the counterparty's credit ratings, the counterparty's market role and deemed creditworthiness and the importance of our business relationship with the counterparty. 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 negatively impact our financial results or stock price;
- legal and administrative proceedings and settlements;
- general industry trends;
- economic conditions, including the impact of any recession or economic downturn;
- investor sentiment relating to climate change and utilization of fossil fuels in connection with power generation could reduce demand for, or increase potential volatility in the market price of, our common stock;
- the severity, magnitude and duration of pandemics, including the COVID-19 pandemic, and the resulting effects on our results of operations, financial condition and cash flows;
- the severity, magnitude and duration of extreme weather events (including Winter Storm Uri), drought and limitations on access to water, and other weather conditions and natural phenomena, contingencies and uncertainties relating thereto, most of which are difficult to predict and many of which are beyond our control, and the resulting effects on our results of operations, financial condition and cash flows;
- acts of sabotage, wars or terrorist or cybersecurity threats or activities;
- risk of contract performance claims by us or our counterparties, and risks of, or costs associated with, pursuing or defending such claims;

- our ability to collect trade receivables from counterparties in the amount or at the time expected, if at all;
- our ability to attract, retain and profitably serve 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 counterparties and suppliers to provide or deliver commodities, materials, or services 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, ancillary services, 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;
- our ability to mitigate forced outage risk, including managing risk associated with Capacity Performance 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 and achieve our capital allocation, performance, and cost-saving initiatives and objectives;
- our ability to generate sufficient cash flow to make principal and interest payments in respect of, or refinance, our debt obligations;
- our expectation that we will continue to pay a comparable cash dividend on a quarterly basis;
- our ability to implement and successfully execute upon our strategic and growth initiatives, including the completion and integration of mergers, acquisitions and/or joint venture activity, the identification and completion of sales and divestitures activity, and the completion and commercialization of our other business development and construction projects;
- 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 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 stockholders and the Board of Directors of Vistra Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vistra Corp. and its subsidiaries (the "Company") as of December 31, 2021 and 2020, 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, 2021, and the related notes and the schedule listed in the Index at Item 15(b) (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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 25, 2022, 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 35 years. Changes to either the estimated timing or amount of expected TRA payments impact the carrying value of the obligation. As of December 31, 2021, the carrying value of the TRA obligation totaled $395 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 the evaluation of 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 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 the Company's 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 assets and liabilities whose fair values are based on complex proprietary models and/or unobservable inputs. These financial instruments can span a broad array of product types and generally include (1) electricity purchases and sales that include power and heat rate positions; (2) physical electricity options, spread options, swaptions, and natural gas options; (3) forward purchase contracts of congestion revenue rights and financial transmission rights; and (4) contracts for natural gas, coal, and environmental allowances. Under accounting principles generally accepted in the United States of America, these financial instruments are generally classified as Level 3 derivative assets or liabilities. As of December 31, 2021, the fair value of the Level 3 derivative assets and liabilities totaled $442 million and $802 million, respectively.

Given management uses complex proprietary models and/or unobservable inputs to estimate the fair value of Level 3 derivative assets and liabilities, performing audit procedures to evaluate the reasonableness of the fair value of Level 3 derivative assets and liabilities 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 evaluation of 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 obtained the Company's complete listing of derivative assets and liabilities and related fair values as of December 31, 2021, to confirm our understanding of the types of instruments outstanding.
- We assessed the consistency by which management has applied significant unobservable valuation assumptions.

- 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.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 25, 2022

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

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

	Year Ended December 31, 2021	2020	2019
Operating revenues (Note 5)	$ 12,077	$ 11,443	$ 11,809
Fuel, purchased power costs and delivery fees	(9,169)	(5,174)	(5,742)
Operating costs	(1,559)	(1,622)	(1,530)
Depreciation and amortization	(1,753)	(1,737)	(1,640)
Selling, general and administrative expenses	(1,040)	(1,035)	(904)
Impairment of long-lived and other assets	(71)	(356)	—
Operating income (loss)	(1,515)	1,519	1,993
Other income (Note 21)	140	34	56
Other deductions (Note 21)	(16)	(42)	(15)
Interest expense and related charges (Note 21)	(384)	(630)	(797)
Impacts of Tax Receivable Agreement (Note 8)	53	5	(37)
Equity in earnings of unconsolidated investment (Note 21)	—	4	16
Income (loss) before income taxes	(1,722)	890	1,216
Income tax (expense) benefit (Note 7)	458	(266)	(290)
Net income (loss)	(1,264)	624	926
Net (income) loss attributable to noncontrolling interest	(10)	12	2
Net income (loss) attributable to Vistra	$ (1,274)	$ 636	$ 928
Weighted average shares of common stock outstanding:			
Basic	482,214,544	488,668,263	494,146,268
Diluted	482,214,544	491,090,468	499,935,490
Net income (loss) per weighted average share of common stock outstanding:			
Basic	$ (2.69)	$ 1.30	$ 1.88
Diluted	$ (2.69)	$ 1.30	$ 1.86

See Notes to the Consolidated Financial Statements.

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

	Year Ended December 31, 2021	2020	2019
Net income (loss)	$ (1,264)	$ 624	$ 926
Other comprehensive income (loss), net of tax effects:			
Effects related to pension and other retirement benefit obligations (net of tax expense (benefit) of $9, ($5) and ($4))	32	(18)	(8)
Total other comprehensive income (loss)	32	(18)	(8)
Comprehensive income (loss)	(1,232)	606	918
Comprehensive income (loss) attributable to noncontrolling interest	(10)	12	2
Comprehensive income (loss) attributable to Vistra	$ (1,242)	$ 618	$ 920

See Notes to the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2021	2020	2019
Cash flows — operating activities:			
Net income (loss)	$ (1,264)	$ 624	$ 926
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:			
Depreciation and amortization	2,050	2,048	1,876
Deferred income tax expense (benefit), net	(475)	230	281
Impairment of long-lived and other assets	71	356	—
Loss on disposal of investment in NELP	—	29	—
Unrealized net (gain) loss from mark-to-market valuations of commodities	759	(231)	(696)
Unrealized net (gain) loss from mark-to-market valuations of interest rate swaps	(134)	155	220
Change in asset retirement obligation liability	(5)	7	(48)
Asset retirement obligation accretion expense	38	43	53
Impacts of Tax Receivable Agreement	(53)	(5)	37
Bad debt expense	110	110	82
Stock-based compensation	47	65	47
Other, net	41	(22)	(12)
Changes in operating assets and liabilities:			
Accounts receivable — trade	(228)	(33)	(88)
Inventories	(100)	(59)	(44)
Accounts payable — trade	402	(40)	(221)
Commodity and other derivative contractual assets and liabilities	32	27	98
Margin deposits, net	(1,000)	(20)	170
Uplift securitization proceeds receivable from ERCOT	(544)	—	—
Accrued interest	13	(20)	80
Accrued taxes	(20)	22	(4)
Accrued employee incentive	(68)	39	1
Tax Receivable Agreement payment	(2)	—	(2)
Asset retirement obligation settlement	(88)	(118)	(121)
Major plant outage deferral	2	2	(19)
Other — net assets	(27)	219	(22)
Other — net liabilities	237	(91)	142
Cash provided by (used in) operating activities	(206)	3,337	2,736
Cash flows — investing activities:			
Capital expenditures, including nuclear fuel purchases and LTSA prepayments	(1,033)	(1,259)	(713)
Ambit acquisition (net of cash acquired)	—	—	(506)
Crius acquisition (net of cash acquired)	—	—	(374)
Proceeds from sales of nuclear decommissioning trust fund securities	483	433	431
Investments in nuclear decommissioning trust fund securities	(505)	(455)	(453)
Proceeds from sales of environmental allowances	392	165	197
Purchases of environmental allowances	(605)	(504)	(322)
Insurance proceeds	89	35	23
Proceeds from sale of assets	30	24	6

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

	Year Ended December 31,		
	2021	2020	2019
Other, net	(4)	(11)	(6)
Cash used in investing activities	(1,153)	(1,572)	(1,717)
Cash flows — financing activities:			
Issuances of preferred stock	2,000	—	—
Issuances of long-term debt	1,250	—	6,507
Repayments/repurchases of debt	(381)	(1,008)	(7,109)
Borrowings under Term Loan A	1,250	—	—
Repayment under Term Loan A	(1,250)	—	—
Proceeds from forward capacity agreement	500	—	—
Net borrowings/(payments) under accounts receivable financing	(300)	(150)	111
Borrowings under Revolving Credit Facility	1,450	1,075	650
Repayments under Revolving Credit Facility	(1,450)	(1,425)	(300)
Debt tender offer and other financing fees	(13)	(17)	(203)
Share repurchases	(471)	—	(656)
Dividends paid to stockholders	(290)	(266)	(243)
Other, net	(21)	(5)	6
Cash provided by (used in) financing activities	2,274	(1,796)	(1,237)
Net change in cash, cash equivalents and restricted cash	915	(31)	(218)
Cash, cash equivalents and restricted cash — beginning balance	444	475	693
Cash, cash equivalents and restricted cash — ending balance	$ 1,359	$ 444	$ 475

See Notes to the Consolidated Financial Statements.

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	December 31, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,325	$ 406
Restricted cash (Note 21)	21	19
Trade accounts receivable — net (Note 21)	1,397	1,279
Income taxes receivable	15	—
Inventories (Note 21)	610	515
Commodity and other derivative contractual assets (Note 16)	2,513	748
Margin deposits related to commodity contracts	1,263	257
Uplift securitization proceeds receivable from ERCOT (Note 1)	544	—
Prepaid expense and other current assets	195	205
Total current assets	7,883	3,429
Restricted cash (Note 21)	13	19
Investments (Note 21)	2,049	1,759
Operating lease right-of-use assets (Note 12)	40	45
Property, plant and equipment — net (Note 21)	13,056	13,499
Goodwill (Note 6)	2,583	2,583
Identifiable intangible assets — net (Note 6)	2,146	2,446
Commodity and other derivative contractual assets (Note 16)	250	258
Accumulated deferred income taxes (Note 7)	1,302	838
Other noncurrent assets	361	332
Total assets	$ 29,683	$ 25,208
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts receivable financing (Note 10)	$ —	$ 300
Long-term debt due currently (Note 11)	254	95
Trade accounts payable	1,515	880
Commodity and other derivative contractual liabilities (Note 16)	3,023	789
Margin deposits related to commodity contracts	39	33
Accrued income taxes	—	16
Accrued taxes other than income	207	210
Accrued interest	143	131
Asset retirement obligations (Note 21)	104	103
Operating lease liabilities (Note 12)	5	8
Other current liabilities	553	471
Total current liabilities	5,843	3,036
Long-term debt, less amounts due currently (Note 11)	10,477	9,235
Operating lease liabilities (Note 12)	38	40
Commodity and other derivative contractual liabilities (Note 16)	804	624
Accumulated deferred income taxes (Note 7)	—	1
Tax Receivable Agreement obligation (Note 8)	394	447
Asset retirement obligations (Note 21)	2,346	2,333
Other noncurrent liabilities and deferred credits (Note 21)	1,489	1,131
Total liabilities	21,391	16,847

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	December 31, 2021	December 31, 2020
Commitments and Contingencies (Note 13)		
Total equity (Note 14):		
Preferred stock, number of shares authorized — 100,000,000; Series A (liquidation preference — $1,000; shares outstanding: December 31, 2021 — 1,000,000; December 31, 2020 — zero); Series B (liquidation preference — $1,000; shares outstanding: December 31, 2021 — 1,000,000; December 31, 2020 — zero)	2,000	—
Common stock (par value — $0.01; number of shares authorized — 1,800,000,000) (shares outstanding: December 31, 2021 — 469,072,597; December 31, 2020 — 489,305,888)	5	5
Treasury stock, at cost (shares: December 31, 2021 — 63,856,879; December 31, 2020 — 41,043,224)	(1,558)	(973)
Additional paid-in-capital	9,824	9,786
Retained deficit	(1,964)	(399)
Accumulated other comprehensive loss	(16)	(48)
Stockholders' equity	8,291	8,371
Noncontrolling interest in subsidiary	1	(10)
Total equity	8,292	8,361
Total liabilities and equity	$ 29,683	$ 25,208

See Notes to the Consolidated Financial Statements.

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

	Preferred Stock	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, 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 loss	—	—	—	—	928	—	928	(2)	926
Dividends declared on common stock	—	—	—	—	(243)	—	(243)	—	(243)
Adoption of new accounting standards	—	—	—	—	(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
Effects of stock-based compensation	—	—	—	65	—	—	65	—	65
Net income (loss)	—	—	—	—	636	—	636	(12)	624
Dividends declared on common stock	—	—	—	—	(266)	—	(266)	—	(266)
Adoption of new accounting standard	—	—	—	—	(4)	—	(4)	—	(4)
Pension and OPEB liability — change in funded status	—	—	—	—	—	(18)	(18)	—	(18)
Investment by noncontrolling interest	—	—	—	—	—	—	—	1	1
Other	—	—	—	—	(1)	—	(1)	—	(1)
Balances at December 31, 2020	$ —	$ 5	$ (973)	$ 9,786	$ (399)	$ (48)	$ 8,371	$ (10)	$ 8,361
Stock repurchases			(585)				(585)		(585)
Series A Preferred Stock issued	1,000	—	—	(10)	—	—	990	—	990
Series B Preferred Stock issued	1,000			(15)			985	—	985
Effects of stock-based compensation	—	—	—	60	—	—	60	—	60
Net income (loss)	—	—	—	—	(1,274)	—	(1,274)	10	(1,264)
Dividends declared on common stock	—	—	—	—	(290)	—	(290)	—	(290)
Pension and OPEB liability — change in funded status	—	—	—	—	—	32	32	—	32
Investment by noncontrolling interest	—	—	—	—	—	—	—	1	1

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

	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interest in Subsidiary	Total Equity
Other	—	—	—	3	(1)	—	2	—	2
Balances at December 31, 2021	$ 2,000	$ 5	$(1,558)	$ 9,824	$(1,964)	$ (16)	$ 8,291	$ 1	$ 8,292

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 and/or its subsidiaries, as apparent in the context. See *Glossary* for defined terms.

Vistra is a holding company operating an integrated retail and electric power generation business primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy market activities including electricity generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and natural gas to end users. Effective July 2, 2020, we changed our name from Vistra Energy Corp. to Vistra Corp. (Vistra) to distinguish from companies that are involved in the exploring for, producing, refining, or transporting fossil fuels (many of which use "energy" in their names) and to better reflect or integrated business model, which combines a retail electricity and natural gas business focused on serving its customers with new and innovative products and services and an electric power generation business leading the clean power transition through our Vistra Zero portfolio while powering the communities we serve with safe, reliable and affordable power.

Vistra has six reportable segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. See Note 20 for further information concerning our reportable business segments, including an update of our reportable segments in the third quarter of 2020.

Winter Storm Uri

In February 2021, a severe winter storm with extremely cold temperatures affected much of the U.S., including Texas. This severe weather resulted in surging demand for power, gas supply shortages, operational challenges for generators, and a significant load shed event that was ordered by ERCOT beginning on February 15, 2021 and continuing through February 18, 2021. Winter Storm Uri had a material adverse impact on our results of operations and operating cash flows. The primary drivers of the loss were the need to procure power in ERCOT at market prices at or near the price cap due to lower output from our natural gas-fueled power plants driven by natural gas deliverability issues and our coal-fueled power plants driven by coal fuel handling challenges, high fuel costs, and high retail load costs.

Uplift Securitization Proceeds Receivable from ERCOT — As part of the 2021 regular Texas legislative sessions and in response to extraordinary costs incurred by electricity market participants during Winter Storm Uri, the Texas legislature passed House Bill (HB) 4492 for ERCOT to obtain financing to distribute to load-serving entities (LSEs) that were uplifted and paid to ERCOT exceptionally high price adders and ancillary service costs during Winter Storm Uri. In October 2021, the PUCT issued a Debt Obligation Order approving $2.1 billion financing and the methodology for allocation of proceeds to the LSEs. In December 2021, ERCOT finalized the amount of allocations to the LSEs, and we expect to receive approximately $544 million of proceeds from ERCOT. The Company accounted for the proceeds we will receive by analogy to the contribution model within Accounting Standards Codification (ASC) 958-605, *Not-for-Profit Entities - Revenue Recognition* and the grant model within International Accounting Standard 20, *Accounting for Government Grants and Disclosure of Government Assistance*, as a reduction to expenses in the statements of operations in the annual period for which the proceeds are intended to compensate. The proceeds are expected to be received from ERCOT in the second quarter of 2022, and we concluded that the threshold for recognizing a receivable was met in December 2021 as the amounts to be received were determinable and ERCOT was directed by its governing body, the PUCT, to take all actions required to effectuate the $2.1 billion funding approved in the Debt Obligation Order. The associated expense reduction is reflected in fuel, purchased power costs and delivery fees within our consolidated statements of operations as that is where the initial costs for which we are being compensated were recorded.

The final financial impact of Winter Storm Uri continues to be subject to the outcome of potential litigation arising from the event, or any corrective action taken by the State of Texas, ERCOT, the RCT, or the PUCT to resettle pricing across any portion of the supply chain (*i.e.*, fuel supply, wholesale pricing of generation, or allocating the financial impacts of market-wide load shed ratably across all retail market participants), that is currently being considered or may be considered by any such parties.

COVID-19 Pandemic

In March 2020, the World Health Organization categorized the novel coronavirus (COVID-19) as a pandemic, and the U.S. Government declared the COVID-19 outbreak a national emergency. The U.S. government has deemed electricity generation, transmission and distribution as "critical infrastructure" providing essential services during this global emergency. As a provider of critical infrastructure, Vistra has an obligation to provide critically needed power to homes, businesses, hospitals and other customers. Vistra remains focused on protecting the health and well-being of its employees and the communities in which it operates while assuring the continuity of its business operations.

The Company's consolidated financial statements reflect estimates and assumptions made by management that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and reported amounts of revenue and expenses during the reporting periods presented. The Company considered the impact of COVID-19 on the assumptions and estimates used and determined that there have been no material adverse impacts on the Company's results of operations for the years ended December 31, 2021 and 2020.

In response to the global pandemic related to COVID-19, the CARES Act was signed into law in March 2020. See Note 7 for a summary of certain anticipated tax-related impacts of the CARES Act to the Company.

Recent Developments

Green Finance Framework — In December 2021, we announced the publication of our Green Finance Framework, which allows us to issue green financial instruments to fund new or existing projects that support renewable energy and energy efficiency with alignment to our ESG initiatives. See below and Note 14 for more information concerning the Series B Preferred Stock, which was issued in December 2021 under the Green Finance Framework.

Series B Preferred Stock Offering — On December 10, 2021, we issued 1,000,000 shares of Series B Preferred Stock in a private offering (Series B Offering) under our Green Finance Network. The net proceeds of the Series B Offering were approximately $985 million, after deducting underwriting commissions and offering expenses. We intend to use the proceeds from the Series B Offering to pay for or reimburse existing and new eligible renewable and battery ESS developments. See Note 14 for more information concerning the Series B Preferred Stock.

Commodity-Linked Revolving Credit Facility — On February 4, 2022, Vistra Operations entered into a credit agreement by and among Vistra Operations, Vistra Intermediate, the lenders, joint lead arrangers and joint bookrunners party thereto, and Citibank, N.A., as administrative agent and collateral agent. The Credit Agreement provides for a $1.0 billion senior secured commodity-linked revolving credit facility (the Commodity-Linked Facility). Vistra Operations intends to use the liquidity provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes. See Note 11 for more information concerning the Commodity-Linked Facility.

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 2020 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. As of December 31, 2021 and 2020, 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/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 $48 million, $43 million and $49 million for the years ended December 31, 2021, 2020 and 2019, 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 is 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. See Note 21 for details of impairments of long-lived assets recorded in 2021 and 2020.

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

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. 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 revenue-based 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 revenue-based 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

Investment tax credits are accounted for under the deferral method, which resulted in a reduction to the basis of our solar and battery storage facilities of zero, zero and $2 million and a corresponding increase in the deferred tax assets in 2021, 2020 and 2019, 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 corporate income tax rate, (b) estimates of our taxable income in the current and future years and (c) additional states that Vistra operates in, including the relevant tax rate and apportionment factor for each state. 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. 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 measured using the discount rate inherent in the initial fair value of the obligation. These changes 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.

Regulatory Asset or Liability

The costs to ultimately decommission the Comanche Peak nuclear power plant are recoverable through the regulatory rate making process as part of Oncor's delivery fees. As a result, the asset retirement obligation and the investments in the decommissioning trust are accounted for as rate regulated operations. Changes in these accounts, including investment income and accretion expense, do not impact net income, but are reported as a change in the corresponding regulatory asset or liability balance that is reflected in our consolidated balance sheets as other noncurrent assets or other noncurrent liabilities and deferred credits.

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 (calculated on a weighted average basis) or net realizable value. 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.

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. We apply the practical expedient permitted by ASC 842 to not separate lease and non-lease components for a majority of our lease asset classes.

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 Accounting Standards Issued Prior to 2021

Simplifying the Accounting for Income Taxes — In December 2019, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2019-12, *Simplifying the Accounting for Income Taxes (Topic 740)*. 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 adopted all provisions of this ASU in the first quarter of 2020, and it did not have a material impact on our financial statements.

Changes to the Disclosure Requirements for Fair Value Measurement — In August 2018, the FASB issued ASU 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement.* 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 requires 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 adopted this ASU in the first quarter of 2020, and the updated disclosures are included in Note 15.

Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract — 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 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 adopted this ASU in the first quarter of 2020, and it did not have a material impact on our financial statements.

Financial Instruments—Credit Losses — 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. We adopted this ASU in the first quarter of 2020, and it did not have a material impact on our financial statements.

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 impact of the adoption of the new lease standard is immaterial to our net income on an ongoing basis. The primary impact of adopting the new lease standard relates to recognition of lease liabilities and ROU assets for all leases classified as operating leases. 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. See Note 12 for the disclosures required by the new lease standard.

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. The ASU provides optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that reference LIBOR or another rate that is expected to be discontinued. The amendments in the ASU are effective for all entities as of March 12, 2020 through December 31, 2022. The adoption of this guidance did not have a material impact on our financial statements.

In March 2020, the SEC amended Rule 3-10 of Regulation S-X regarding financial disclosure requirements for registered debt offerings involving subsidiaries as either issuers or guarantors and affiliates whose securities are pledged as collateral. This new guidance narrows the circumstances that require separate financial statements of subsidiary issuers and guarantors and streamlines the alternative disclosures required in lieu of those statements. This rule is effective January 4, 2021 with earlier adoption permitted. We elected to adopt this rule in the first quarter of 2020. Accordingly, summarized financial information has been presented only for the issuer and guarantors of the Company's registered debt securities, and the location of the required disclosures has been moved outside the Notes to the Consolidated Financial Statements and is provided in Part II, Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations* under *Financial Condition — Guarantor Summary Financial Information*. In October 2020, the FASB issued ASU 2020-09, *Debt (Topic 470) — Amendments to SEC Paragraphs Pursuant to SEC Release No. 33-10762*, to reflect the SEC's new disclosure rules on guaranteed debt securities adopted by the Company.

2. ACQUISITIONS AND BUSINESS COMBINATION ACCOUNTING

Ambit Transaction

On November 1, 2019 (Ambit Acquisition Date), Volt Asset Company, Inc., an indirect, wholly owned subsidiary of Vistra, completed the Ambit Transaction. Ambit is an energy retailer selling both electricity and natural gas products to residential and small business customers in 16 states. Vistra 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.

Crius Transaction

On July 15, 2019 (Crius Acquisition Date), Vienna Acquisition B.C. Ltd., an indirect, wholly owned subsidiary of Vistra, 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 funded the purchase price of $400 million (including $382 million for outstanding trust units) using cash on hand. In addition, Vistra assumed $140 million of outstanding debt and acquired $26 million of cash at the closing of the Crius Transaction. 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'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's match of its generation to load profile due to a high degree of overlap of Vistra'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's match of its generation to load profile due to a high degree of overlap of Vistra's generation fleet with Crius' approximately 10 TWh of annual electricity load, (ii) established a platform for growth by leveraging Vistra'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.

Each of the Ambit Transaction and Crius Transaction, respectively, 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 Ambit Acquisition Date and Crius Acquisition Date, respectively. The combined results of operations are reported in our consolidated financial statements beginning as of the respective Ambit Acquisition Date and Crius Acquisition 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 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 allocation of the purchase price to the fair value amounts recognized for the assets acquired and liabilities assumed related to the Ambit Transaction and Crius Transaction, respectively, as of the Ambit Acquisition Date and Crius Acquisition Date, 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 final purchase price allocations were completed in the second quarter of 2020 for the Crius Transaction and the third quarter of 2020 for the Ambit Transaction.

Ambit Transaction and Crius Transactions Final Purchase Price Allocations

	Ambit Transaction		Crius Transaction	
	Final Purchase Price Allocation	Measurement Period Adjustments recorded	Final Purchase Price Allocation	Measurement Period Adjustments recorded
Cash and cash equivalents	$ 49	$ —	$ 26	$ —
Net working capital	32	3	(9)	(42)
Accumulated deferred income taxes	—	—	—	(36)
Identifiable intangible assets	218	(45)	317	23
Goodwill	258	44	243	38
Commodity and other derivative contractual assets	23	—	18	—
Other noncurrent assets	13	—	17	(3)
Total assets acquired	593	2	612	(20)
Identifiable intangible liabilities	—	—	2	(34)
Long-term debt, including amounts due currently	—	—	140	—
Commodity and other derivative contractual liabilities	28	—	40	—
Accumulated deferred income taxes	—	—	14	14
Other noncurrent liabilities and deferred credits	10	2	16	—
Total liabilities assumed	38	2	212	(20)
Identifiable net assets acquired	$ 555	$ —	$ 400	$ —

Acquisition costs incurred in the Ambit Transaction and Crius Transaction 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 Transaction and Crius Transaction 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 year ended December 31, 2019 assumes that the Ambit and Crius Transactions occurred on January 1, 2019 (i.e., represents our results for the year ended December 31, 2019 plus the results for either Ambit Transaction or Crius Transaction 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 Transaction and Crius Transaction been completed on January 1, 2019, 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, 2019	Year Ended December 31, 2019
Revenues	$ 12,931	$ 12,373
Net income (a)	$ 949	$ 876
Net income attributable to Vistra	$ 951	$ 878
Net income attributable to Vistra per weighted average share of common stock outstanding — basic	$ 1.92	$ 1.78
Net income attributable to Vistra per weighted average share of common stock outstanding — diluted	$ 1.90	$ 1.76

(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.

3. DEVELOPMENT OF GENERATION FACILITIES

Texas Segment Solar Generation and Energy Storage Projects

We have announced our planned development of up to 768 MW of solar photovoltaic power generation facilities and 260 MW of battery ESS in Texas. The first 158 MW of solar generation came online in January and February 2022. Estimated commercial operation dates for the remaining facilities range from the second quarter of 2022 to fourth quarter of 2023. As of December 31, 2021, we had accumulated approximately $286 million in construction-work-in-process for these Texas segment solar generation and battery ESS projects.

East Segment Solar Generation and Energy Storage Projects

In September 2021, we announced the planned development of up to 300 MW of solar photovoltaic power generation facilities and up to 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois, based on the passage of Illinois Senate Bill 2408, the Energy Transition Act. Estimated commercial operation dates for these facilities range from 2023 to 2025.

West Segment Energy Storage Projects

Oakland — In June 2019, East Bay Community Energy (EBCE) 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. In April 2020, the project received necessary approvals from EBCE and from Pacific Gas and Electric Company (PG&E). The contract was amended to increase the capacity of the planned development to a 36.25 MW battery ESS. In April 2020, the concurrent Local Area Reliability Service (LARS) agreement to ensure grid reliability as part of the Oakland Clean Energy Initiative was signed, but required California Public Utilities Commission (CPUC) approval. PG&E did not receive CPUC approval as of April 15, 2021. On April 16, 2021, Vistra terminated the LARS agreement with PG&E. We are continuing development of the Oakland battery ESS project while seeking another contractual arrangement that will allow the investment to move forward.

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 PG&E to develop a 300 MW battery ESS at our Moss Landing Power Plant site in California (Moss Landing Phase I). PG&E filed its application with the CPUC in June 2018 and the CPUC approved the resource adequacy contract in November 2018. 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. Moss Landing Phase I commenced commercial operations in May 2021.

In May 2020, we announced that, subject to approval by the CPUC, we would enter into a 10-year resource adequacy contract with PG&E to develop an additional 100 MW battery ESS at our Moss Landing Power Plant site (Moss Landing Phase II). PG&E filed its application with the CPUC in May 2020 and the CPUC approved the resource adequacy contract in August 2020. Moss Landing Phase II commenced commercial operations in July 2021.

The total development costs for Moss Landing Phases I and II totaled approximately $600 million.

In January 2022, we announced that, subject to approval by the CPUC, we would enter into a 15-year resource adequacy contract with PG&E to develop an additional 350 MW battery ESS at our Moss Landing Power Plant site (Moss Landing Phase III). PG&E filed its application with the CPUC in January 2022, and CPUC approval is expected in the second quarter of 2022. Moss Landing Phase III is expected to enter commercial operations in the summer of 2023.

Moss Landing Outages — In September 2021, Moss Landing Phase I experienced an incident impacting a portion of the battery ESS. A review found that only a small, single-digit percentage of batteries at the facility were impacted and that the root cause originated in systems separate from the battery system. The facility will be offline as we perform the work necessary to return the facility to service. Moss Landing Phase II was not affected by this incident.

In February 2022, Moss Landing Phase II experienced an incident impacting a portion of the Battery ESS. An investigation is underway to determine the root cause of the incident. The facility will be offline as we perform the work necessary to return the facility to service. Moss Landing Phase I was not affected by the incident, but the facility will remain offline during the assessment stage of the Moss Landing Phase II incident.

We do not expect these incidents to have a material impact on our results of operations.

4. RETIREMENT OF GENERATION FACILITIES

Sunset Segment

Operational results for plants with defined retirement dates identified below are included in our Sunset segment beginning in the quarter when a retirement plan is announced.

Name	Location	ISO/RTO	Fuel Type	Net Generation Capacity (MW)	Expected Retirement Date (a)
Baldwin	Baldwin, IL	MISO	Coal	1,185	By the end of 2025
Coleto Creek	Goliad, TX	ERCOT	Coal	650	By the end of 2027
Edwards	Bartonville, IL	MISO	Coal	585	By the end of 2022
Joppa	Joppa, IL	MISO	Coal	802	By September 1, 2022
Joppa	Joppa, IL	MISO	Natural Gas	221	By September 1, 2022
Kincaid	Kincaid, IL	PJM	Coal	1,108	By the end of 2027
Miami Fort	North Bend, OH	PJM	Coal	1,020	By the end of 2027
Newton	Newton, IL	MISO/PJM	Coal	615	By the end of 2027
Zimmer	Moscow, OH	PJM	Coal	1,300	By May 31, 2022
Total				7,486	

(a) Generation facilities may retire earlier than expected dates if economic or other conditions dictate.

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 U.S. District Court for the Central District of Illinois in November 2019, we will retire the Edwards facility by the end of 2022 (see Note 13).

In September 2020 and December 2020, we announced our intention to retire all of our remaining coal generation facilities in Illinois and Ohio, one coal generation facility in Texas and one natural gas facility in Illinois no later than year-end 2027 due to economic challenges, including incremental expenditures that would be required to comply with the CCR rule and ELG rule (see Note 13), and in furtherance of our efforts to significantly reduce our carbon footprint. Expected plant retirement expenses of $43 million, driven by severance cost, were accrued in the year ended December 31, 2020 in operating costs of our Sunset segment.

In April 2021, we announced we would retire the Joppa generation facilities by September 1, 2022 in order to settle a complaint filed with the Illinois Pollution Control Board (IPCB) by the Sierra Club in 2018 (see Note 13). We had previously announced that Joppa would retire no later than the end of 2027. In July 2021, we announced we would retire the Zimmer coal generation facility by May 31, 2022 due to the inability to secure capacity revenues for the plant in the latest PJM capacity auction held in May 2021. We had previously announced that Zimmer would retire no later than the end of 2027.

See Note 21 for discussion of impairments recorded in connection with these announcements.

Asset Closure Segment

Operational results for the Illinois plants retired in 2019 identified below are included in the Asset Closure segment. The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines, including those retired prior to 2019.

Name	Location	ISO/RTO	Fuel Type	Net Generation Capacity (MW)	Dates Units Retired
Coffeen	Coffeen, IL	MISO	Coal	915	November 1, 2019
Duck Creek	Canton, IL	MISO	Coal	425	December 15, 2019
Havana	Havana, IL	MISO	Coal	434	November 1, 2019
Hennepin	Hennepin, IL	MISO	Coal	294	November 1, 2019
Total				2,068	

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 (MPS rule) that require us to retire approximately 2,000 MW of generation capacity. In light of the provisions of the Federal Power Act and the FERC regulations thereunder, the affected subsidiaries of Vistra 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 were included primarily in operating costs of our Asset Closure segment in our consolidated statements of operations. 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.

5. REVENUE

The following tables disaggregate our revenue by major source:

	Year Ended December 31, 2021							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations	Consolidated
Revenue from contracts with customers:								
Retail energy charge in ERCOT	$ 5,733	$ —	$ —	$ —	$ —	$ —	$ —	$ 5,733
Retail energy charge in Northeast/ Midwest	2,255	—	—	—	—	—	—	2,255
Wholesale generation revenue from ISO/RTO	—	3,808	786	229	1,525	—	—	6,348
Capacity revenue from ISO/RTO (a)	—	—	(22)	1	184	—	—	163
Revenue from other wholesale contracts	—	2,302	602	104	193	—	—	3,201
Total revenue from contracts with customers	7,988	6,110	1,366	334	1,902	—	—	17,700
Other revenues:								
Intangible amortization	(2)	—	74	—	(12)	—	—	60
Hedging and other revenues (b)	(115)	(4,355)	123	35	(1,371)	—	—	(5,683)
Affiliate sales (c)	—	1,035	1,024	5	220	—	(2,284)	—
Total other revenues	(117)	(3,320)	1,221	40	(1,163)	—	(2,284)	(5,623)
Total revenues	$ 7,871	$ 2,790	$ 2,587	$ 374	$ 739	$ —	$ (2,284)	$ 12,077

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $470 million of capacity purchased offset by $448 million of capacity sold. The Sunset segment includes $4 million of capacity purchased offset by $188 million of capacity sold.

(b) Includes $1.191 billion of unrealized net losses from mark-to-market valuations of commodity positions. See Note 20 for unrealized net gains (losses) by segment.

(c) Texas and East segments include $1.028 billion and $529 million, respectively, of affiliated unrealized net losses from mark-to-market valuations of commodity positions with the Retail segment.

	Year Ended December 31, 2020							
	Retail	Texas	East	West	Sunset	Asset Closure	Eliminations	Consolidated
Revenue from contracts with customers:								
Retail energy charge in ERCOT	$ 5,813	$ —	$ —	$ —	$ —	$ —	$ —	$ 5,813
Retail energy charge in Northeast/ Midwest	2,406	—	—	—	—	—	—	2,406
Wholesale generation revenue from ISO/RTO	—	475	310	124	473	1	—	1,383
Capacity revenue from ISO/RTO (a)	—	—	(52)	—	164	—	—	112
Revenue from other wholesale contracts	—	226	668	54	187	1	—	1,136
Total revenue from contracts with customers	8,219	701	926	178	824	2	—	10,850
Other revenues:								
Intangible amortization	(5)	—	2	—	(21)	—	—	(24)
Hedging and other revenues (b)	56	416	(108)	101	151	1	—	617
Affiliate sales	—	2,999	1,595	3	298	—	(4,895)	—
Total other revenues	51	3,415	1,489	104	428	1	(4,895)	593
Total revenues	$ 8,270	$ 4,116	$ 2,415	$ 282	$ 1,252	$ 3	$ (4,895)	$ 11,443

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $542 million of capacity purchased offset by $490 million of capacity sold. The Sunset segment includes $3 million of capacity purchased offset by $167 million of capacity sold.

(b) Includes $164 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, 2019							
	Retail	Texas	East	West	Sunset	Asset Closure	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	—	1,477	629	193	751	194	—	3,244
Capacity revenue from ISO/RTO (a)	—	—	170	—	197	11	—	378
Revenue from other wholesale contracts	—	264	702	9	147	2	—	1,124
Total revenue from contracts with customers	6,801	1,741	1,501	202	1,095	207	—	11,547
Other revenues:								
Intangible amortization	(15)	—	(4)	4	(17)	—	—	(32)
Hedging and other revenues (b)	86	(250)	37	132	247	42	—	294
Affiliate sales	—	2,345	1,256	—	277	92	(3,970)	—
Total other revenues	71	2,095	1,289	136	507	134	(3,970)	262
Total revenues	$ 6,872	$ 3,836	$ 2,790	$ 338	$ 1,602	$ 341	$ (3,970)	$ 11,809

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $443 million of capacity purchased offset by $613 million of capacity sold. The Sunset segment includes $1 million of capacity purchased offset by $198 million of capacity sold.

(b) 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.

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 60 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/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 operates as a market participant within ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO and expects to continue to remain under contract with each ISO/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/RTO in the same period, the excess of the amount sold over the amount purchased is reflected in wholesale generation revenues.

Capacity Revenue From ISO/RTO

We offer generation capacity into competitive ISO/RTO auctions in exchange for revenue from awarded capacity offers. Capacity ensures installed generation and demand response is available to satisfy system integrity and reliability requirements. Capacity revenues are recognized when the performance obligation is satisfied ratably over time as our power generation facilities stand ready to deliver power to the customer. Penalties are assessed by the ISO/RTO against generation facilities if the facility is not available during the capacity period. The penalties are recorded as a reduction to revenue. When capacity is sold to and purchased from the same ISO/RTO in the same period, the excess of the amount sold over the amount purchased is reflected in capacity revenue.

Revenue from Other Wholesale Contracts

Other wholesale contracts include other revenue activity with the ISO/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 operates as a market participant within ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO and expects to continue to remain under contract with each ISO/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 both December 31, 2021 and 2020 was $80 million. The amortization related to these costs during the year ended December 31, 2021, 2020 and 2019 totaled $75 million, $46 million and $21 million respectively, recorded as SG&A expenses, and $6 million, $7 million and $9 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, 2021, we have future performance obligations that are unsatisfied, or partially unsatisfied, relating to capacity auction volumes awarded through capacity auctions held by the ISO/RTO or contracts with customers. Therefore, an obligation exists as of the date of the results of the respective ISO/RTO capacity auction or the contract execution date. These obligations total $652 million, $310 million, $212 million, $99 million and $45 million that will be recognized in the years ending December 31, 2022, 2023, 2024, 2025 and 2026, respectively, and $439 million thereafter. Capacity revenues are recognized as capacity is made available to the related ISOs/RTOs or 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,	
	2021	**2020**
Trade accounts receivable from contracts with customers — net	$ 1,087	$ 1,169
Other trade accounts receivable — net	310	110
Total trade accounts receivable — net	$ 1,397	$ 1,279

6. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS AND LIABILITIES

Goodwill

The following table provides information regarding our goodwill balance.

Balance at December 31, 2018	$ 2,068
Measurement period adjustments recorded in connection with the Merger	14
Goodwill recorded in connection with the Crius Transaction	257
Goodwill recorded in connection with the Ambit Transaction	214
Balance at December 31, 2019	2,553
Measurement period adjustments recorded in connection with the Crius Transaction	(14)
Measurement period adjustments recorded in connection with the Ambit Transaction	44
Balance at December 31, 2021 and 2020	$ 2,583

As of December 31, 2021, the carrying value of goodwill totaled $2.583 billion and consisted of the following:

- $1.907 billion arose in connection with our application of fresh start reporting at Emergence and was allocated entirely to our 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.
- $175 million arose in connection with the Merger, of which $122 million was allocated to our Texas Generation reporting unit and $53 million was allocated to our Retail reporting unit. None of the goodwill related to the Merger is deductible for tax purposes.
- $243 million of goodwill arose in connection with the Crius Transaction and was allocated entirely to our Retail reporting unit. None of the goodwill related to the Crius Transaction is deductible for tax purposes.
- $258 million of goodwill arose in connection with the Ambit Transaction and was allocated entirely to our Retail reporting unit. The goodwill related to the Ambit Transaction 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. 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 Retail and Texas Generation reporting units exceeded their carrying value at October 1, 2021. 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, 2021			December 31, 2020		
Identifiable Intangible Asset	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**
Retail customer relationship	$ 2,083	$ 1,631	$ 452	$ 2,082	$ 1,434	$ 648
Software and other technology-related assets	421	206	215	414	186	228
Retail and wholesale contracts	248	206	42	272	204	68
Contractual service agreements (a)	23	2	21	51	1	50
Other identifiable intangible assets (b)	95	20	75	96	19	77
Total identifiable intangible assets subject to amortization	$ 2,870	$ 2,065	805	$ 2,915	$ 1,844	1,071
Retail trade names (not subject to amortization) (c)			1,341			1,374
Mineral interests (not currently subject to amortization)			—			1
Total identifiable intangible assets			$ 2,146			$ 2,446

(a) As of December 31, 2021 and 2020, 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).
(c) During the year ended December 31, 2021, we recorded a $33 million impairment to a retail trade name intangible asset.

Identifiable intangible liabilities are comprised of the following:

	Year Ended December 31,	
Identifiable Intangible Liability	**2021**	**2020**
Contractual service agreements	$ 125	$ 129
Purchase and sale of power and capacity	8	87
Fuel and transportation purchase contracts	14	73
Total identifiable intangible liabilities	$ 147	$ 289

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, 2021 (weighted average in years)	Year Ended December 31, 2021	2020	2019
Retail customer relationship	Depreciation and amortization	3	$ 197	$ 283	$ 275
Software and other technology-related assets	Depreciation and amortization	4	74	73	61
Retail and wholesale contracts/purchase and sale/fuel and transportation contracts	Operating revenues/fuel, purchased power costs and delivery fees	3	(56)	17	23
Other identifiable intangible assets	Operating revenues/fuel, purchased power costs and delivery fees/depreciation and amortization	5	279	223	148
Total intangible asset expense (a)			$ 494	$ 596	$ 507

(a) Amounts recorded in depreciation and amortization totaled $275 million, $360 million and $340 million for the years ended December 31, 2021, 2020 and 2019 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 certificate 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.

- *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 assets represent the fair value of our retail brands, including the trade names of TXU Energy™, Ambit Energy, 4Change Energy™, Homefield Energy, Dynegy Energy Services, TriEagle Energy, Public Power and U.S. Gas & Electric, and were determined to be indefinite-lived assets not subject to amortization. These intangible assets are 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 estimates include estimated gross margins for future periods and implied royalty rates. On the most recent testing date, we recorded an impairment charge for $33 million related to an immaterial trade name. For all other trade names, we determined it was more likely than not that the fair value of the retail trade name intangible assets exceeded their carrying values at October 1, 2021.

- *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, 2021, 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	
2022	$	202
2023	$	148
2024	$	99
2025	$	73
2026	$	49

7. INCOME TAXES

Vistra files a U.S. federal income tax return that includes the results of its consolidated subsidiaries. Vistra is the corporate parent of the Vistra 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,		
	2021	2020	2019
Current:			
U.S. Federal	$ 1	$ (5)	$ (1)
State	16	41	10
Total current	17	36	9
Deferred:			
U.S. Federal	(336)	171	260
State	(139)	59	21
Total deferred	(475)	230	281
Total	$ (458)	$ 266	$ 290

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

	Year Ended December 31,		
	2021	2020	2019
Income (loss) before income taxes	$ (1,722)	$ 890	$ 1,216
U.S. federal statutory rate	21 %	21 %	21 %
Income taxes at the U.S. federal statutory rate	(362)	187	255
Nondeductible TRA accretion	(8)	(7)	5
State tax, net of federal benefit	(2)	32	48
Federal and State return to provision adjustment	(2)	13	(17)
Nondeductible compensation	4	—	3
Nondeductible transaction costs	—	—	2
Equity awards	1	—	(4)
Valuation allowance on state NOLs	(94)	41	13
Lignite depletion	(3)	(3)	(6)
Texas gross margin amended return	—	—	(3)
Other	8	3	(6)
Income tax expense (benefit)	$ (458)	$ 266	$ 290
Effective tax rate	26.6 %	29.9 %	23.8 %

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2021 and 2020 are as follows:

	December 31,	
	2021	2020
Noncurrent Deferred Income Tax Assets		
Tax credit carryforwards	$ 76	$ 75
Loss carryforwards	1,193	953
Identifiable intangible assets	346	293
Long-term debt	15	19
Employee benefit obligations	121	129
Commodity contracts and interest rate swaps	238	96
Other	148	47
Total deferred tax assets	$ 2,137	$ 1,612
Noncurrent Deferred Income Tax Liabilities		
Property, plant and equipment	767	632
Total deferred tax liabilities	767	632
Valuation allowance	68	143
Net Deferred Income Tax Asset	$ 1,302	$ 837

As of December 31, 2021, we had total deferred tax assets of approximately $1.302 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 impacts of Winter Storm Uri as well as the Merger. For the year ended December 31, 2021, we recognized a tax benefit of $74 million on the release of state valuation allowances largely related to Illinois. Illinois enacted legislation in 2021 extending the carryforward period of net operating losses and we forecast to utilize all losses before expiration. For the year ended December 31, 2020, we recognized a partial valuation allowance of $32 million on the net operating loss carryforwards related largely to Illinois and New York due to forecasted expiration. As of December 31, 2021, 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.

As of December 31, 2021, we had $4.5 billion pre-tax net operating loss (NOL) carryforwards for federal income tax purposes that will begin to expire in 2032. As of December 31, 2021, we had no remaining 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 liability of $9 million at December 31, 2021 and a net deferred tax asset of $5 million at December 31, 2020.

Coronavirus Aid, Relief, and Economic Security Act (CARES Act) and Final Section 163(j) Regulations

In response to the global pandemic related to COVID-19, the CARES Act was signed into law in March 2020. The CARES Act provides numerous relief provisions for corporate taxpayers, including modification of the utilization limitations on net operating losses, favorable expansion of the deduction for business interest expense under IRC Section 163(j) (Section 163(j)), the ability to accelerate timing of refundable AMT credits and the temporary suspension of certain payment requirements for the employer portion of social security taxes. Additionally, the final Section 163(j) regulations were issued in July 2020 and provided a critical correction to the proposed regulations with respect to the computation of adjusted taxable income. In 2021, Vistra is benefiting from the final 163(j) regulations and able to utilize its remaining 163(j) carryforward of $12 million. Certain provisions in the final 163(j) regulations begin to sunset in 2022, for which Vistra will continue its legislative monitoring and advocacy efforts to amend consistent with the intent of the law, including the permanent addback of depreciation and amortization to adjusted taxable income. Vistra is also utilizing the CARES Act payroll deferral mechanism to defer the payment of approximately $22 million from 2020 to 2021 and 2022. We paid approximately half of the previously deferred taxes in December 2021.

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, 2021, 2020 and 2019. 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, 2021, 2020 and 2019.

	Year Ended December 31,		
	2021	2020	2019
Balance at beginning of period, excluding interest and penalties	$ 39	$ 126	$ 39
Additions based on tax positions related to prior years	1	3	3
Reductions based on tax positions related to prior years	—	(90)	—
Additions based on tax positions related to the current year	—	—	87
Settlements with taxing authorities	(2)	—	(3)
Balance at end of period, excluding interest and penalties	$ 38	$ 39	$ 126

Vistra and its subsidiaries file income tax returns in U.S. federal, state and foreign jurisdictions and are, at times, subject to examinations by the IRS and other taxing authorities. In February 2021, Vistra was notified that the IRS had opened a federal income tax audit for tax years 2018 and 2019 and an employment tax audit for tax year 2018. Crius is currently under audit by the IRS for the tax years 2015 and 2016. Uncertain tax positions totaled $38 million at December 31, 2021.

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 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 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).

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, 2021, 2020 and 2019.

	Year Ended December 31,		
	2021	2020	2019
TRA obligation at the beginning of the period	$ 450	$ 455	$ 420
Accretion expense	62	64	59
Changes in tax assumptions impacting timing of payments (a)	(115)	(69)	(22)
Impacts of Tax Receivable Agreement	(53)	(5)	37
Payments	(2)	—	(2)
TRA obligation at the end of the period	395	450	455
Less amounts due currently	(1)	(3)	—
Noncurrent TRA obligation at the end of the period	$ 394	$ 447	$ 455

(a) During the year ended December 31, 2021, we recorded a decrease to the carrying value of the TRA obligation totaling $115 million as a result of adjustments to forecasted taxable income, including the financial impacts of Winter Storm Uri, and anticipated tax benefits available under current tax laws for planned additional renewable development projects. During the year ended December 31, 2020, we recorded a decrease to the carrying value of the TRA obligation totaling approximately $69 million as a result of adjustments to forecasted taxable income, including the impacts of the CARES Act, changes to Section 163(j) percentage limitation amount, the impacts from the issuance of the final Section 163(j) regulations and the anticipated tax benefits from renewable development projects. During the year ended December 31, 2019, we recorded an 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's state income tax profile, including the Dynegy, Crius and Ambit acquisitions.

As of December 31, 2021, the estimated carrying value of the TRA obligation totaled $395 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%, (b) estimates of our taxable income in the current and future years and (c) additional states that Vistra 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. The estimates of future business results include assumptions related to renewable development projects that Vistra is planning to execute that generate significant tax benefits. These benefits have a material impact on the timing of TRA obligation payments. 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, 2021, 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 paid during the next 15 years, and the final payment expected to be made around the year 2056 (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,		
	2021	2020	2019
Net income (loss) attributable to Vistra	$ (1,274)	$ 636	$ 928
Less cumulative dividends attributable to Series A Preferred Stock	(17)	—	—
Less cumulative dividends attributable to Series B Preferred Stock	(4)	—	—
Net income (loss) attributable to common stock — basic	(1,295)	636	928
Weighted average shares of common stock outstanding — basic	482,214,544	488,668,263	494,146,268
Net income (loss) per weighted average share of common stock outstanding — basic	$ (2.69)	$ 1.30	$ 1.88
Dilutive securities: Stock-based incentive compensation plan	—	2,422,205	5,789,223
Weighted average shares of common stock outstanding — diluted	482,214,544	491,090,468	499,935,490
Net income (loss) per weighted average share of common stock outstanding — diluted	$ (2.69)	$ 1.30	$ 1.86

Stock-based incentive compensation plan awards excluded from the calculation of diluted earnings per share because the effect would have been antidilutive totaled 14,412,299, 12,553,414 and 2,447,850 shares for the years ended December 31, 2021, 2020 and 2019, respectively.

10. ACCOUNTS RECEIVABLE FINANCING

Accounts Receivable Securitization Program

TXU Energy Receivables Company LLC (RecCo), an indirect subsidiary of Vistra, has an accounts receivable financing facility (Receivables Facility) provided by issuers of asset-backed commercial paper and commercial banks (Purchasers). In December 2020, the Receivables Facility was amended to include Ambit Texas, LLC (Ambit Texas), Value Based Brands and TriEagle Energy, as originators, and increase the commitment of the Purchasers to $500 million for the remaining term of the Receivables Facility. In February 2021, the Receivables Facility was amended to allow for a one-time, $596 million borrowing to take advantage of a higher receivable balance at such time. The borrowing limit returned to $500 million in March 2021. In March 2021, the Receivables Facility was amended to increase the commitment of the Purchasers to $600 million through the July 2021 renewal. The Receivables Facility was renewed in July 2021, extending the term of the Receivables Facility to July 2022, with the ability to borrow $600 million beginning with the settlement date in July 2021 until the settlement date in August 2021, $725 million from the settlement date in August 2021 until the settlement date in November 2021 and $600 million from the settlement date in November 2021 and thereafter for the remaining term of the Receivables Facility.

In connection with the Receivables Facility, TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands and TriEagle Energy, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), each sell and/or contribute, subject to certain exclusions, all of its receivables (other than any receivables excluded pursuant to the terms of the Receivables Facility), arising from the sale of electricity to its customers and related rights (Receivables), to RecCo, a consolidated, wholly owned, bankruptcy-remote, direct subsidiary of TXU Energy. RecCo, in turn, is subject to certain conditions, and may draw under the Receivables Facility up to the limits described above to fund its acquisition of the Receivables from the Originators. RecCo has granted a security interest on the Receivables and all related assets for the benefit of the Purchasers under the Receivables Facility and Vistra Operations has agreed to guarantee the obligations under the agreements governing the Receivables Facility. 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's balance sheet and Vistra 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 Receivables on behalf of RecCo and the Purchasers, as applicable.

As of December 31, 2021, there were no outstanding borrowings under the Receivables Facility. As of December 31, 2020, outstanding borrowings under the Receivables Facility totaled $300 million and were supported by $735 million of RecCo gross receivables.

Repurchase Facility

In October 2020, TXU Energy and the other originators under the Receivables Facility entered into a $125 million repurchase facility (Repurchase Facility) that is provided on an uncommitted basis by a commercial bank as buyer (Buyer). In July 2021, the Repurchase Facility was renewed until August 2021 and increased from $125 million to $150 million. In August 2021, the Repurchase Facility was renewed until July 2022 and the facility size was decreased from $150 million to $125 million. The Repurchase Facility is collateralized by a subordinated note (Subordinated Note) issued by RecCo in favor of TXU Energy for the benefit of Originators under the Receivables Facility and representing a portion of the outstanding balance of the purchase price paid for the Receivables sold by the Originators to RecCo under the Receivables Facility. Under the Repurchase Facility, TXU Energy may request that Buyer transfer funds to TXU Energy in exchange for a transfer of the Subordinated Note, with a simultaneous agreement by TXU Energy to transfer funds to Buyer at a date certain or on demand in exchange for the return of the Subordinated Note (collectively, the Transactions). Each Transaction is expected to have a term of one month, unless terminated earlier on demand by TXU Energy or terminated by Buyer after an event of default.

TXU Energy and the other Originators have each granted Buyer a first-priority security interest in the Subordinated Note to secure its obligations under the agreements governing the Repurchase Facility, and Vistra Operations has agreed to guarantee the obligations under the agreements governing the Repurchase Facility. Unless earlier terminated under the agreements governing the Repurchase Facility, the Repurchase Facility will terminate concurrently with the schedule termination of the Receivables Facility.

There were no outstanding borrowings under the Repurchase Facility at both December 31, 2021 and December 31, 2020.

11. LONG-TERM DEBT

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

	December 31, 2021	December 31, 2020
Vistra Operations Credit Facilities	$ 2,543	$ 2,572
Vistra Operations Senior Secured Notes:		
3.550% Senior Secured Notes, due July 15, 2024	1,500	1,500
3.700% Senior Secured Notes, due January 30, 2027	800	800
4.300% Senior Secured Notes, due July 15, 2029	800	800
Total Vistra Operations Senior Secured Notes	3,100	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	1,300
5.000% Senior Unsecured Notes, due July 31, 2027	1,300	1,300
4.375% Senior Unsecured Notes, due May 15, 2029	1,250	—
Total Vistra Operations Senior Unsecured Notes	4,850	3,600
Other:		
Forward Capacity Agreements	213	45
Equipment Financing Agreements	92	68
8.82% Building Financing due semiannually through February 11, 2022 (a)	3	10
Other	3	3
Total other long-term debt	311	126
Unamortized debt premiums, discounts and issuance costs	(73)	(68)
Total long-term debt including amounts due currently	10,731	9,330
Less amounts due currently	(254)	(95)
Total long-term debt less amounts due currently	$ 10,477	$ 9,235

(a) 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 current assets in our consolidated balance sheets.

Vistra Operations Credit Facilities

As of December 31, 2021, the Vistra Operations Credit Facilities consisted of up to $5.268 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 $2.543 billion (Term Loan B-3 Facility). These amounts reflect the following transactions and amendments completed in 2021, 2020 and 2019:

- In March 2021, Vistra Operations borrowed $1.0 billion principal amount under the Term Loan A Facility. In April 2021, Vistra Operations borrowed an additional $250 million principal amount under the Term Loan A Facility. Proceeds from the Term Loan A Facility, together with cash on hand, were used to repay certain amounts outstanding under the Revolving Credit Facility. Borrowings under the Term Loan A Facility were reported in short-term borrowings in our condensed consolidated balance sheet. In May 2021, Vistra Operations used the proceeds from the issuance of the Vistra Operations 4.375% senior unsecured notes due 2029 (described below), together with cash on hand, to repay the $1.250 billion borrowings under the Term Loan A Facility. We recorded an extinguishment loss of $1 million on the transaction in the nine months ended September 30, 2021.

- In March 2020, Vistra Operations repurchased and cancelled $100 million principal amount of Term Loan B-3 Facility borrowings at a weighted average price of $93.875. We recorded an extinguishment gain of $6 million on the transaction in the year ended December 31, 2020.

- 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 to pay the principal, premium and interest due in connection with the redemption by Vistra 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 Offerings (described below) to repay $889 million 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 for the year ended December 31, 2019, which were capitalized as a noncurrent asset.

During the year ended December 31, 2021, we borrowed $1.450 billion and repaid $1.450 billion under the Revolving Credit Facility, with proceeds from the borrowings used for general corporate purposes.

The Vistra Operations Credit Facilities and related available capacity at December 31, 2021 are presented below.

		December 31, 2021			
Vistra Operations Credit Facilities	**Maturity Date**	**Facility Limit**	**Cash Borrowings**	**Letters of Credit Outstanding**	**Available Capacity**
Revolving Credit Facility (a)	June 14, 2023	$ 2,725	$ —	$ 1,471	$ 1,254
Term Loan B-3 Facility (b)	December 31, 2025	2,543	2,543		—
Total Vistra Operations Credit Facilities		$ 5,268	$ 2,543	$ 1,471	$ 1,254

(a) Revolving Credit Facility used for general corporate purposes. The Facility includes a $2.35 billion letter of credit sub-facility. Letters of credit outstanding reduce our available capacity. Cash borrowings under the Revolving Credit Facility are reported in short-term borrowings in our consolidated balance sheets.
(b) 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.

As of December 31, 2021, cash borrowings under the Revolving Credit Facility would bear interest based on applicable LIBOR rates, plus a fixed spread of 1.75%, and there were no outstanding borrowings. Letters of credit issued under the Revolving Credit Facility bear interest of 1.75%. Amounts borrowed under the Term Loan B-3 Facility bears interest based on applicable LIBOR rates plus fixed spreads of 1.75%. As of December 31, 2021, the weighted average interest rates before taking into consideration interest rate swaps on outstanding borrowings was 1.86% under the Term Loan B-3 Facility. 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 Vistra Operations Credit Facilities, not to exceed 4.25 to 1.00. As of December 31, 2021, 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 employs interest rate swaps to hedge our exposure to variable rate debt. As of December 31, 2021, Vistra 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%

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

During 2019, Vistra entered into $2.12 billion of new interest rate swaps, pursuant to which Vistra 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 $2.30 billion of debt through July 2026.

Commodity-Linked Revolving Credit Facility

On February 4, 2022, Vistra Operations entered into a credit agreement by and among Vistra Operations, Vistra Intermediate, the lenders, joint lead arrangers and joint bookrunners party thereto, and Citibank, N.A., as administrative agent and collateral agent. The Credit Agreement provides for a $1.0 billion senior secured commodity-linked revolving credit facility (the Commodity-Linked Facility). Under the Commodity-Linked Facility, the borrowing base is calculated on a weekly basis based on a set of theoretical transactions which approximate the hedge portfolio of Vistra Operations and certain of its subsidiaries in certain power markets, with availability thereunder not to exceed the facility limit nor be less than zero. Vistra Operations may, at its option, borrow an amount up to the borrowing base, as adjusted from time to time, provided that if outstanding borrowings at any time would exceed the borrowing base, Vistra Operations shall make a repayment to reduce outstanding borrowings to be less than or equal to the borrowing base. Vistra Operations intends to use the liquidity provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes.

Secured Letter of Credit Facilities

In August and September 2020, Vistra entered into uncommitted standby letter of credit facilities that are each secured by a first lien on substantially all of Vistra Operations' (and its subsidiaries') assets (which ranks pari passu with the Vistra Operations Credit Facilities) (each, a Secured LOC Facility and collectively, the Secured LOC Facilities). The Secured LOC Facilities are used for general corporate purposes. In October 2021, Vistra entered into an additional Secured LOC Facility which will also be used for general corporate purposes. As of December 31, 2021, $406 million of letters of credit were outstanding under the Secured LOC Facilities.

Alternate Letter of Credit Facilities

Two alternate letter of credit facilities (each, an Alternate LOC Facility) became effective in the years ended December 31, 2018 and 2019, respectively. One Alternate LOC Facility with an aggregate facility limit of $250 million matured in December 2020. The remaining Alternate LOC Facility with an aggregate facility limit of $250 million matured 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 (June 2019 Senior Secured Notes and the November 2019 Senior Secured Notes) in offerings (the June 2019 Senior Secured Notes Offering and the November 2019 Senior Secured Notes Offering) to eligible purchasers under Rule 144A and Regulation S under the Securities Act 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

(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 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 indenture (as may be amended or supplemented from time to time, the Vistra Operations Senior Secured Indenture) governing the June 2019 Senior Secured Notes and the November 2019 Senior Secured Notes (collectively, the Senior Secured Notes) provides for the full and unconditional guarantee 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. The Vistra Operations Senior Secured Indenture contains certain covenants and restrictions, including, among others, restrictions on the ability of Vistra Operations 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 Operations Senior Unsecured Notes

In 2019 and 2021, Vistra Operations issued and sold $3.9 billion aggregate principal amount of senior unsecured notes in offerings (the February 2019 Senior Unsecured Notes Offering, June 2019 Senior Unsecured Notes Offerings and the May 2021 Senior Unsecured Offerings) to eligible purchasers under Rule 144A and Regulation S under the Securities Act consisting of the following:

Senior Unsecured Notes	Maturity Year	Interest Terms (Due Semiannually in Arrears)	February 2019 Senior Unsecured Notes Offering (a)	June 2019 Senior Unsecured Notes Offering (b)	May 2021 Senior Unsecured Notes Offering (c)
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	—
4.375% Senior Unsecured Notes	2029	May 1 and November 1	—	—	1,250
Total			$ 1,300	$ 1,300	$ 1,250
Net Proceeds			$ 1,287	$ 1,287	$ 1,235
Debt issuance and other fees (d)			$ 16	$ 13	$ 15

____

(a) The 5.625% senior unsecured notes due 2027 (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, (defined below) and (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).
(b) The 5.000% senior unsecured notes due 2027 (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 (defined below) 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
(c) The 4.375% senior unsecured notes due 2029 (the May 2021 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 all amounts outstanding under the Term Loan A Facility and to pay fees and expenses of $15 million related to the offering.
(d) Capitalized as a reduction in the carrying amount of the debt.

Since 2018, Vistra Operations has issued and sold $4.850 billion aggregate principal amount of senior unsecured notes in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The indentures governing the May 2021 Senior Unsecured Notes, the June 2019 Senior Unsecured Notes, the February 2019 Senior Unsecured Notes and the 5.500% senior unsecured notes due 2026 (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 Vistra Operations and its subsidiaries, as applicable, to create certain liens, merge or consolidate with another entity, and sell all or substantially all of their assets.

Debt Repurchase Program

In July 2019, the Board authorized up to $1.0 billion to repay or repurchase any outstanding debt of the Company (or its subsidiaries). Through April 2020, $684 million of debt had been repurchased under the $1.0 billion July 2019 authorization, including the repurchase of $100 million principal amount of Term Loan B-3 Facility borrowings discussed above and the redemption of $81 million aggregate principal amount outstanding of 8.000% senior unsecured notes due 2025 (8.000% senior notes) discussed below. In April 2020, the Board authorized up to $1.0 billion to repay or repurchase additional outstanding debt, with this new authority superseding and replacing the $316 million of availability under the previously authorized $1.0 billion debt repurchase program. Through December 31, 2021, approximately $666 million had been repurchased under the $1.0 billion April 2020 authorization, consisting of the redemption of the Vistra 5.875% senior unsecured notes due 2023 (5.875% senior notes) and the redemption of the Vistra 8.125% senior unsecured notes due 2026 (8.125% senior notes), each as described below.

Vistra Senior Unsecured Notes

On the Merger Date, Vistra assumed $6.138 billion principal amount of Dynegy's senior unsecured notes (Vistra Senior Unsecured Notes). 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 following amounts reflect redemption, repurchase and tender offer transactions completed in 2019 and 2020. Vistra had no outstanding senior notes at the Parent level as of December 31, 2021 and 2020.

Vistra Senior Unsecured Notes	Maturity Year	February 2019 Tender Offer (a)	June 2019 Tender Offer (b)	2019 Redemptions (c)	2020 Redemptions (d)
6.750%Senior Unsecured Notes	2019	$ —	$ —	$ —	$ —
7.375% Senior Unsecured Notes	2022	1,193	173	341	—
5.875% Senior Unsecured Notes	2023	—	—	—	500
7.625% Senior Unsecured Notes	2024	—	672	475	—
8.034% Senior Unsecured Notes	2024	—	—	25	—
8.000% Senior Unsecured Notes	2025	—	—	—	81
8.125%Senior Unsecured Notes	2026	—	—	—	166
Total		$ 1,193	$ 845	$ 841	$ 747
Extinguishment gain/(loss)		$ 7	$ 7	$ 11	$ 11

(a) In February 2019, Vistra 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.

(b) In June 2019, Vistra 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 $173 million of 7.375% senior notes and $672 million of 7.625% senior notes. In July 2019, Vistra 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.

(c) In November 2019, Vistra redeemed $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 (the 2019 Redemption). Vistra redeemed $341 million, $87 million and $25 million aggregate principal amount of 7.375% senior notes, 7.625% senior notes and 8.034% senior notes, respectively, using proceeds from the February 2019 Senior Unsecured Notes Offering and the June 2019 Senior Unsecured Notes Offerings discussed above.

(d) In January 2020, June 2020 and July 2020, Vistra redeemed aggregate principal amounts of $81 million of 8.000% senior notes, $500 million of 5.875% senior notes and $166 million of 8.125% senior notes, respectively, at redemption prices of 104%, 100.979% and 104.063%, respectively, of the aggregate principal amounts thereof, plus accrued and unpaid interest to, but excluding, the dates of redemption (the 2020 Redemptions, and together with the 2019 Redemption, the Redemptions).

February 2019 Consent Solicitation — In connection with the February 2019 Tender Offer, Vistra also commenced solicitation of consents from holders of the 7.375% senior notes. Vistra 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.

Other Long-Term Debt

Amortizing Notes — On the Merger Date, Vistra 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 — In March 2021, the Company sold a portion of the PJM capacity that cleared for Planning Years 2021-2022 to a financial institution (2021-2022 Forward Capacity Agreement). The buyer in this transaction will receive capacity payments from PJM during the Planning Years 2021-2022 in the amount of approximately $515 million. 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 a debt issuance with an implied interest rate of approximately 4.25%.

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 (Legacy Forward Capacity Agreements, and, together with the 2021-2022 Forward Capacity Agreement, the Forward Capacity Agreements). In May 2021, the final capacity payment from PJM during the Planning Years 2020-2021 was paid, and the terms of the Legacy Forward Capacity were fulfilled.

Equipment Financing Agreements — On the Merger Date, the Company assumed the obligation of Dynegy's agreements under 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 financed these parts and equipment under agreements with maturities ranging from 2021 to 2026.

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 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 Connecticut Department of Economic and Community Development term loans were repaid using cash on hand.

Maturities

Long-term debt maturities at December 31, 2021 are as follows:

	December 31, 2021
2022	$ 258
2023	40
2024	1,540
2025	2,470
2026	1,006
Thereafter	5,490
Unamortized premiums, discounts and debt issuance costs	(73)
Total long-term debt, including amounts due currently	$ 10,731

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 36 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,		
	2021	2020	2019
Operating lease cost	$ 11	$ 14	$ 14
Finance lease:			
Finance lease right-of-use asset amortization	9	7	4
Interest on lease liabilities	10	7	4
Total finance lease cost	19	14	8
Variable lease cost (a)	29	29	26
Short-term lease cost	35	31	19
Sublease income (b)	(7)	(8)	(8)
Net lease cost	$ 87	$ 80	$ 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, 2021	December 31, 2020
Lease assets:		
Operating lease right-of-use assets	$ 40	$ 45
Finance lease right-of-use assets (net of accumulated depreciation)	173	$ 182
Total lease right-of-use assets	213	227
Current lease liabilities:		
Operating lease liabilities	5	8
Finance lease liabilities	8	8
Total current lease liabilities	13	16
Noncurrent lease liabilities:		
Operating lease liabilities	38	40
Finance lease liabilities	235	206
Total noncurrent lease liabilities	273	246
Total lease liabilities	$ 286	$ 262

Cash Flows and Other Information

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

	Year Ended December 31, 2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 11	$ 17	$ 17
Operating cash flows from finance leases	9	5	4
Finance cash flows from finance leases	5	10	4
Non-cash disclosure upon commencement of new lease:			
Right-of-use assets obtained in exchange for new operating lease liabilities	7	14	95
Right-of-use assets obtained in exchange for new finance lease liabilities	—	108	13
Non-cash disclosure upon modification of existing lease:			
Modification of operating lease right-of-use assets	(4)	(1)	(41)
Modification of finance lease right-of-use assets	(1)	23	50

Weighted Average Remaining Lease Term

The following table presents weighted average remaining lease term information:

	December 31, 2021	December 31, 2020
Weighted average remaining lease term:		
Operating lease	17.6 years	12.3 years
Finance lease	25.0 years	24.2 years
Weighted average discount rate:		
Operating lease	5.76%	5.80 %
Finance lease	4.95%	4.92 %

Maturity of Lease Liabilities

The following table presents maturity of lease liabilities:

	Operating Lease	Finance Lease	Total Lease
2022	$ 6	$ 17	$ 23
2023	7	16	23
2024	4	17	21
2025	3	17	20
2026	3	14	17
Thereafter	51	369	420
Total lease payments	74	450	524
Less: Interest	(31)	(207)	(238)
Present value of lease liabilities	$ 43	$ 243	$ 286

13. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

As of December 31, 2021, we had minimum contractual commitments under long-term service and maintenance contracts, energy-related contracts, leases and other agreements as follows.

	Long-Term Service and Maintenance Contracts (a)	Coal transportation agreements	Pipeline transportation and storage reservation fees	Water Contracts
2022	$ 202	$ 104	$ 86	$ 9
2023	268	22	54	9
2024	236	24	40	9
2025	207	25	36	9
2026	196	26	23	9
Thereafter	2,130	27	91	58
Total	$ 3,239	$ 228	$ 330	$ 103

(a) Long-term service and maintenance contracts reflect expected expenditures as these contracts do not include minimum spending requirements, but can only be terminated based on events outside the control of the Company.

In addition to the commitments detailed above, we have nuclear fuel contracts with early termination penalties. As of December 31, 2021, termination costs of $54 million would be incurred if we terminated those contracts.

Expenditures under our coal purchase and coal transportation agreements totaled $850 million, $845 million, and $1.092 billion for the years ended December 31, 2021, 2020 and 2019, respectively.

Guarantees

We have entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. Material guarantees are discussed below.

Letters of Credit

As of December 31, 2021, we had outstanding letters of credit totaling $1.877 billion as follows:

- $1.558 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/RTOs;
- $157 million to support battery and solar development projects;
- $27 million to support executory contracts and insurance agreements;
- $74 million to support our REP financial requirements with the PUCT; and
- $61 million for other credit support requirements.

Surety Bonds

As of December 31, 2021, we had outstanding surety bonds totaling $561 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 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 plaintiffs in these 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. In December 2021, we settled an individual action with Reorganized FLI, Inc., as successor to Farmland Industries, Inc., that was pending in Kansas federal court, and that case has now been dismissed. We remain as a defendant in one other action, which is a consolidated putative class action lawsuit pending in federal court in Wisconsin.

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. In March 2018, BNSF Railway Company (BNSF) and Norfolk Southern Railway Company (NS) filed a demand for arbitration. In March 2021, the parties entered into a confidential settlement to resolve this matter and the Coffeen matter discussed below. In connection with that settlement, BNSF and NS dismissed with prejudice their arbitration disputes for Wood River and Coffeen and these matters are fully resolved.

Coffeen and Duck Creek Rail Disputes — In April 2020, IPH, LLC (IPH) received notification that BNSF and NS were initiating dispute resolution related to IPH's suspension of its Coffeen Rail Transportation Agreement with the railroads, and Illinois Power Resources Generating, LLC (IPRG), received notification that BNSF was initiating dispute resolution related to IPRG's suspension of its Duck Creek Rail Transportation Agreement with BNSF. In November 2019, IPH and IPRG sent suspension notices to the railroads asserting that the MPS rule requirement to retire at least 2,000 megawatts of generation (see discussion below) was a change-in-law under the agreement that rendered continued operation of the plants no longer economically feasible. In addition, IPH and IPRG asserted that the MPS rule's retirement requirement also qualified as a *force majeure* event under the agreements excusing performance. In March 2021, we entered into a confidential settlement agreement with BNSF to resolve the Duck Creek matter and a separate confidential settlement agreement with BNSF and NS to resolve the Coffeen and Wood River matter discussed above. BNSF has dismissed with prejudice the Duck Creek arbitration dispute and this matter is now fully resolved. The settlement of these rail disputes did not have a material impact on our financial statements.

Winter Storm Uri Legal Proceedings

Repricing Challenges — In March 2021, we filed an appeal in the Third Court of Appeals in Austin, Texas (Third Court of Appeals), challenging the PUCT's February 15 and February 16, 2021 orders governing ERCOT's determination of wholesale power prices during load-shedding events. We filed our opening brief in June 2021, and response briefs were filed in September 2021. In our brief, we argue that the prior PUCT rushed to adopt a rule that dramatically raised the price of electricity in ERCOT, but in doing so failed to follow any of the rulemaking procedures required for the PUCT to undertake an emergency rulemaking, and we have asked the court to vacate this rule. Other parties also filed briefs in support of our challenge to the PUCT's orders. In addition, we have also submitted settlement disputes with ERCOT over power prices and other issues during Winter Storm Uri. Following an appeal of the PUCT's March 5, 2021 verbal order and other statements made by the PUCT, the Texas Attorney General, on behalf of the PUCT, its client, represented in a letter agreement filed with the Third Court of Appeals that the PUCT has not prejudged or made a final decision on whether to reprice and that we and other parties may continue disputing the pricing through the ERCOT process.

Koch Disputes — In March 2021, we filed a lawsuit in Texas state court against Odessa-Ector Power Partners, L.P., Koch Resources, LLC, Koch AG & Energy Solutions, LLC, and Koch Energy Services, LLC (Koch) seeking equitable relief in which we contested the amount of the February 2021 earnout payment under the terms of the 2017 asset purchase agreement (APA) with Koch. Koch subsequently filed its own related lawsuit in Delaware Chancery Court, and the Delaware Chancery Court ruled that all claims related to the APA dispute (including our equitable claims) would proceed in Delaware. We contested Koch's demand for $286 million for the February 2021 earnout payment as an unjust windfall and inconsistent with the parties' intent when they entered into the APA in 2017. We recorded a $286 million liability in other noncurrent liabilities and deferred credits in our consolidated balance sheets. In March 2021, we also filed a lawsuit in New York state court against Koch for breach of contract and ineffective notice of force majeure related to Koch's failure to deliver contracted-for quantities of gas during Winter Strom Uri, which Koch removed to federal court. In November 2021, the disputes we had with Koch were resolved to the parties' mutual satisfaction and all the lawsuits have been dismissed. The matter was resolved within the amount that was reserved and will be paid in the second quarter of 2022.

Regulatory Investigations and Other Litigation Matters — Following the events of Winter Storm Uri, various regulatory bodies, including ERCOT, the ERCOT Independent Market Monitor, the Texas Attorney General, the FERC and the NRC initiated investigations or issued requests for information of various parties related to the significant load shed event that occurred during the event as well as operational challenges for generators arising from the event, including performance and fuel and supply issues. We responded to all those investigatory requests. In addition, a number of personal injury and wrongful death lawsuits related to Winter Storm Uri have been filed in various Texas state courts against us and numerous generators, transmission and distribution utilities, retail and electric providers, as well as ERCOT. We and other defendants requested that all pretrial proceedings in these personal injury cases be consolidated and transferred to a single multi-district litigation (MDL) pretrial judge. In June 2021, the MDL panel granted the request to consolidate all these cases into a MDL for pretrial proceedings. In addition, in January 2022, an insurance subrogation lawsuit was filed in Austin state court by over one hundred insurance companies against ERCOT, Vistra and several other defendants. The lawsuit seeks recovery of insurance funds paid out by these insurance companies to various policyholders for claims related to Winter Storm Uri. We believe we have strong defenses to this lawsuit and the other tort lawsuits and intend to defend against these cases vigorously.

Climate Change

In January 2021, the Biden administration issued a series of Executive Orders, including one titled *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (the Environment Executive Order) which directed agencies, including the EPA, to review various agency actions promulgated during the prior administration and take action where the previous administration's action conflicts with national objectives. Several of the EPA agency actions discussed below are now subject to this review.

Greenhouse Gas Emissions (GHG)

In July 2019, the EPA finalized a rule to that repealed the Clean Power Plan (CPP) that had been finalized in 2015 and established new regulations addressing GHG emissions from existing coal-fueled electric generation units, referred to as the Affordable Clean Energy (ACE) rule. The ACE rule developed emission guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. In response to challenges brought by Environmental groups and certain states, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the ACE rule, including the repeal of the CPP, in January 2021 and remanded the rule to the EPA for further action. In October 2021, the U.S. Supreme Court granted four petitions for certiorari of the D.C. Circuit Court's decision and consolidated the cases for review. The case is now fully briefed and scheduled for oral argument in February 2022. Additionally, in January 2021, the EPA, just prior to the transition to the Biden administration, issued a final rule setting forth a significant contribution finding for the purpose of regulating GHG emissions from new, modified, or reconstructed electric utility generating units. In April 2021, the D.C. Circuit Court granted the EPA's unopposed motion for voluntary vacatur and remand of the GHG significant contribution rule. The ACE rule and the rule on significant contribution are subject to the Environment Executive Order discussed above.

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

In October 2017, the EPA issued a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas' 2009 State Implementation Plan (SIP) and a partial Federal Implementation Plan (FIP). For SO_2, the rule established 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 the 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. For NO_X, the rule adopted the CSAPR's ozone program as BART and for particulate matter, the rule approved Texas's SIP that determines that no electricity generation units are subject to BART for particulate matter. In August 2020, the EPA issued a final rule affirming the prior BART final rule but also included additional revisions that were proposed in November 2019. Challenges to both the 2017 rule and the 2020 rules have been consolidated in the D.C. Circuit Court, where we have intervened in support of the EPA. We are in compliance with the rule, and the retirements of our Monticello, Big Brown and Sandow 4 plants have enhanced our ability to comply. The BART rule is subject to the Environment Executive Order discussed above, and the EPA has stated it is starting a proceeding for reconsideration of the BART rule. The challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's action on reconsideration.

SO_2 Designations for Texas

In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Martin Lake generation plant and our now-retired Big Brown and Monticello 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 U.S. Court of Appeals for the Fifth Circuit (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 have revised its previous nonattainment designations and each area at issue would be designated unclassifiable. In August 2020, the EPA issued a Finding of Failure for Texas to submit an attainment plan. In May 2021, the EPA finalized a "Clean Data" determination for the areas surrounding the retired Big Brown and Monticello plants, redesignating those areas as attainment based on monitoring data supporting an attainment designation. In June 2021, the EPA published two notices; one that it was withdrawing the August 2019 Error Correction Rule and a second separate notice denying petitions from Luminant and the State of Texas to reconsider the original nonattainment designations. We, along with the State of Texas, challenged that EPA action and have consolidated it with the pending challenge in the Fifth Circuit Court, with the matter likely being fully briefed by March 2022. In September 2021, the TCEQ considered a proposal for its nonattainment SIP revision for the Martin Lake area and an agreed order to reduce SO_2 emissions from the plant. The proposed agreed order associated with the SIP proposal reduces emission limits as of January 2022. Emission reductions required are those necessary to demonstrate attainment with the NAAQS. The TCEQ's SIP action was finalized in February 2022 and will be submitted to the EPA for review and approval.

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. Based on these administrative developments, the Fifth Circuit Court agreed to sever and hold in abeyance challenges to those 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. The EPA published a final rule in October 2020 that extends the compliance date for both FGD and bottom ash transport water to no later than December 2025, as negotiated with the state permitting agency. Additionally, the final rule allows for a retirement exemption that exempts facilities certifying that units will retire by December 2028 provided certain effluent limitations are met. In November 2020, environmental groups petitioned for review of the new ELG revisions, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. In July 2021, the EPA announced its intent to revise the ELG rule and moved to hold the 2020 ELG revision litigation in abeyance pending the EPA's completion of its reconsideration rulemaking. Notifications were made to Texas, Illinois and Ohio state agencies on the retirement exemption for applicable coal plants by the regulatory deadline of October 13, 2021.

Coal Combustion Residuals (CCR)/Groundwater

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. In August 2020, the EPA issued a final rule establishing a deadline of April 11, 2021 to cease receipt of waste and initiate closure at unlined CCR impoundments. The final rule allows a generation plant to seek the EPA's approval to extend this deadline if no alternative disposal capacity is available and either a conversion to comply with the CCR rule is underway or retirement will occur by either 2023 or 2028 (depending on the size of the impoundment at issue). Prior to the November 2020 deadline, we submitted applications to the EPA requesting compliance extensions under both conversion and retirement scenarios. In November 2020, environmental groups petitioned for review of this rule in the D.C. Circuit Court, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. Also, in November 2020, the EPA finalized a rule that would allow an alternative liner demonstration for certain qualifying facilities. In November 2020, we submitted an alternate liner demonstration for one CCR unit at Martin Lake. In August 2021, we submitted a request to transfer our conversion application for the Zimmer facility to a retirement application following announcement that Zimmer will close by May 31, 2022. In January 2022, the EPA determined that our conversion and retirement applications for our CCR facilities were complete but has not yet made a final determination on any of those applications.

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 have completed closure activities at those ponds at our Baldwin facility.

At our retired Vermilion facility, which was not potentially 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 (PRN) filed a citizen suit in federal court in Illinois against 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. In June 2021, the U.S. Court of Appeals for the Seventh Circuit affirmed the district court's dismissal of the lawsuit, but stated that PRN may refile. 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. We answered that complaint in July 2021, and this matter remains 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, which is owned by our subsidiary DMG, and that notice was referred to the Illinois Attorney General. In June 2021, the Illinois Attorney General and the Vermilion County State Attorney filed a complaint in Illinois state court with an agreed interim consent order which the court subsequently entered. Given the violation notices and the enforcement action, the unique characteristics of the site, and the proximity of the site to the only national scenic river in Illinois, we agreed to enter into the interim consent order to resolve this matter. Per the terms of the agreed interim consent order, DMG is required to evaluate the closure alternatives under the requirements of the newly implemented Illinois Coal Ash regulation (discussed below) and close the site by removal. In addition, the interim consent order requires that during the impoundment closure process, impacted groundwater will be collected before it leaves the site or enters the nearby Vermilion river and, if necessary, DMG will be required to install temporary riverbank protection if the river migrates within a certain distance of the impoundments. These proposed closure costs are reflected in the ARO in our condensed consolidated balance sheets (see Note 21).

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. Under the final rule, which was finalized and became effective in April 2021, 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 rule does not mandate closure by removal at any site. In May 2021, we filed an appeal in the Illinois Fourth Judicial District over certain provisions of the final rule. We filed our opening brief in October 2021. Other parties have also filed appeals of certain provisions of the final rule. In October 2021, we filed operating permit applications for 18 impoundments as required by the Illinois coal ash rule, and filed construction permit applications for three of our sites in January 2022.

For all of the above matters, if certain corrective action measures, including groundwater treatment or removal of ash, are required 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. The Illinois coal ash rule was finalized in April 2021 and does not require removal. However, the rule will require us to undertake further site specific evaluations required by each program. We will not know the full range of decommissioning costs, including groundwater remediation, if any, that ultimately may be required under the Illinois rule until permit applications have been submitted and approved by the IEPA. However, the currently anticipated CCR surface impoundment and landfill closure costs, as reflected in our existing ARO liabilities, 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 request for rehearing was denied by FERC in March 2020. The order was appealed by Public Citizen, Inc. to the D.C. Circuit Court in May 2020, and Vistra, Dynegy and Illinois Power Marketing Company intervened in the case in June 2020. In August 2021, the D.C. Circuit Court issued a ruling denying Public Citizen, Inc.'s arguments that FERC failed to meet its obligation to ensure just and reasonable rates because it did not review the prices resulting from the auction before those prices went into effect and that FERC was arbitrary and capricious in failing to adequately explain its decision to close its investigation into whether Dynegy engaged in market manipulation. The D.C. Circuit Court of Appeals granted Public Citizen, Inc.'s petition in part finding that FERC's decision that the auction results were just and reasonable solely because the auction process complied with the filed tariff was unreasoned and remanded the case back to FERC for further proceedings on that issue. On February 4, 2022 the Illinois Attorney General and Public Citizen, Inc. filed a motion at FERC requesting that FERC on remand reverse its prior decision and either find that auction results were not just and reasonable and order Dynegy to pay refunds to Illinois or, in the alternative, initiate an evidentiary hearing and discovery. We intend to vigorously defend our position, including by filing a response to the motion.

Other Matters

We are involved in various legal and administrative proceedings and other disputes 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 current collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal-, natural gas- and nuclear-fueled generation operations, as well as some battery operations, expire on various dates between March 2022 and May 2024, 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 our existing 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, nuclear accident 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 nuclear 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 U.S. 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 U.S., each operating licensed reactor in the U.S. 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 by November 2023. Assessments are currently limited to $20.5 million per operating licensed reactor per year per incident. As of December 31, 2021, 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 accident decontamination and reactor damage stabilization 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 accident decontamination and reactor damage stabilization insurance for our Comanche Peak facility in the amount of $2.25 billion and non-nuclear accident related property damage in the amount of $1.0 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

Common Stock Issuances and Repurchases

Changes in the number of shares of common stock issued and outstanding for the years ended December 31, 2021, 2020 and 2019 are reflected in the table below.

	Shares Issued	Treasury Shares	Shares Outstanding
Balance at December 31, 2018	526,031,092	(32,815,783)	493,215,309
Shares issued (a) (b)	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
Shares issued (a)	1,611,462	—	1,611,462
Shares retired	(3,685)	—	(3,685)
Balance at December 31, 2020	530,349,112	(41,043,224)	489,305,888
Shares issued (a)	2,583,761	—	2,583,761
Shares retired	(3,397)	—	(3,397)
Shares repurchased (c)	—	(27,988,518)	(27,988,518)
Balance at December 31, 2021	532,929,476	(69,031,742)	463,897,734

(a) Shares issued includes share awards granted to nonemployee directors.
(b) 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.
(c) Shares repurchased in the year ended December 31, 2021 include 5,174,863 of unsettled shares as of December 31, 2021.

Share Repurchase Programs

In October 2021, we announced that the Board has authorized a new share repurchase program (Share Repurchase Program) under which up to $2.0 billion of our outstanding shares of common stock may be repurchased. The Share Repurchase Program became effective on October 11, 2021, at which time it superseded the 2020 Share Repurchase Program (described below) and any authorization remaining as of such date. We intend to use the net proceeds from the Offering (described below) to repurchase shares of our outstanding common stock. In the three months ended December 31, 2021, 19,330,365 shares of our common stock were repurchased under the Share Repurchase Program for approximately $409 million at an average price of $21.16 per share of common stock. As of December 31, 2021, approximately $1.591 billion was available for additional repurchases under the Share Repurchase Program. From January 1, 2022 through February 22, 2022, 16,059,290 of our common stock had been repurchased under the Share Repurchase Program for $355 million at an average price per share of common stock of $22.07, and at February 22, 2022, $1.236 billion was available for repurchase under the Share Repurchase Program. We expect to complete repurchases under the Share Repurchase Program by the end of 2022.

Under the Share Repurchase Program, 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 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.

In September 2020, we announced that the Board authorized a share repurchase program (2020 Share Repurchase Program) under which up to $1.5 billion of our outstanding shares of common stock may be repurchased. The 2020 Share Repurchase Program was effective January 1, 2021, at which time the 2018 Share Repurchase Plan (described below) and all authorized amounts remaining thereunder terminated as of such date. In the year ended December 31, 2021, 8,658,153 shares of our common stock were repurchased under the 2020 Share Repurchase Program for approximately $175 million at an average price of $20.21 per share of common stock. The 2020 Share Repurchase Program was superseded by the Share Repurchase Program in October 2021.

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 this authorized amount was fully utilized in 2018. 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 (collectively, 2018 Share Repurchase Program). In the year ended December 31, 2019, 26,322,166 shares of our common stock were repurchased under the 2018 Share Repurchase Program for approximately $640 million (including related fees and expenses) at an average price of $24.34 per share. There were no repurchases under the 2018 Share Repurchase Program in the year ended December 31, 2020. The 2018 Share Repurchase Program was terminated on January 1, 2021.

Preferred Stock

On October 15, 2021 (Series A Issuance Date), we issued of 1,000,000 shares of Series A Preferred Stock in a private offering (Series A Offering). The net proceeds of the Series A Offering were approximately $990 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Series A Offering to repurchase shares of our outstanding common stock under the Share Repurchase Program (described above).

On December 10, 2021 (Series B Issuance Date), we issued of 1,000,000 shares of Series B Preferred Stock in a private offering (Series B Offering). The net proceeds of the Series B Offering were approximately $985 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Series B Offering to pay for or reimburse existing and new eligible renewable and battery ESS developments.

The Series A Preferred Stock and the Series B Preferred Stock are not convertible into or exchangeable for any other securities of the Company and have limited voting rights. The Series A Preferred Stock may be redeemed at the option of the Company at any time after the Series A First Reset Date (defined below) and in certain other circumstances prior to the Series A First Reset Date. The Series B Preferred Stock may be redeemed at the option of the Company at any time after the Series B First Reset Date (defined below) and in certain other circumstances prior to the Series B First Reset Date.

Dividends

Common Stock — In November 2018, Vistra announced the Board adopted a dividend program which we initiated in the first quarter of 2019. 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, Vistra'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, April 2020, July 2020 and October 2020, the Board declared quarterly dividends of $0.135 per share that were paid in March 2020, June 2020, September 2020 and December 2020, respectively.

In February 2021, April 2021, July 2021 and October 2021, the Board declared quarterly dividends of $0.15 per share that were paid in March 2021, June 2021, September 2021 and December 2021, respectively.

In February 2022, the Board declared a quarterly dividend of $0.17 per share that will be paid in March 2022.

Preferred Stock — The annual dividend rate on each share of Series A Preferred Stock is 8.0% from the Series A Issuance Date to, but excluding October 15, 2026 (Series A First Reset Date). On and after the Series A First Reset Date, the dividend rate on each share of Series A Preferred Stock shall equal the five-year U.S. Treasury rate as of the most recent reset dividend determination date (subject to a floor of 1.07%), plus a spread of 6.93% per annum. The Series A Preferred Stock has a liquidation preference of $1,000 per share, plus accumulated but unpaid dividends. Cumulative cash dividends on the Series A Preferred Stock are payable semiannually, in arrears, on each April 15 and October 15, commencing on April 15, 2022, when, as and if declared by the Board.

In February 2022, the Board declared a semi-annual dividend of $40.00 per share of Series A Preferred Stock that will be paid in April 2022.

The annual dividend rate on each share of Series B Preferred Stock is 7.0% from the Series B Issuance Date to, but excluding December 15, 2026 (Series B First Reset Date). On and after the Series B First Reset Date, the dividend rate on each share of Series B Preferred Stock shall equal the five-year U.S. Treasury rate as of the most recent reset dividend determination date (subject to a floor of 1.26%), plus a spread of 5.74% per annum. The Series B Preferred Stock has a liquidation preference of $1,000 per share, plus accumulated but unpaid dividends. Cumulative cash dividends on the Series B Preferred Stock are payable semiannually, in arrears, on each June 15 and December 15, commencing on June 15, 2022, when, as and if declared by the Board.

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, 2021, Vistra Operations can distribute approximately $7.3 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 $405 million, $1.1 billion and $3.9 billion during the years ended December 31, 2021, 2020 and 2019, 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, 2021, all of the restricted net assets of Vistra Operations may be distributed to Parent.

In addition to the restrictions under the Credit Facilities Agreement, under applicable Delaware law, we are only permitted to make distributions either out of "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), or out of net profits for the fiscal year in which the distribution is declared or the prior fiscal year.

Under the terms of the Series A Preferred Stock and the Series B Preferred Stock, unless full cumulative dividends have been or contemporaneously are being paid or declared and a sum sufficient for the payment thereof set apart for payment on all outstanding Series A Preferred Stock (and any parity securities) and Series B Preferred Stock (and any parity securities), respectively, with respect to dividends through the most recent dividend payment dates, (i) no dividend may be declared or paid or set apart for payment on any junior security (other than a dividend payable solely in junior securities with respect to both dividends and the liquidation, winding-up and dissolution of our affairs), including our common stock, and (ii) we may not redeem, purchase or otherwise acquire any parity security or junior security, including our common stock, in each case subject to certain exceptions as described in the certificate of designation of the Series A Preferred Stock and the Series B Preferred Stock, respectively.

Accumulated Other Comprehensive Income

During the years ended December 31, 2021, 2020 and 2019, we recorded changes in the funded status of our pension and other postretirement employee benefit liability totaling $(24) million, $23 million and $11 million, respectively. During the years ended December 31, 2021, 2020 and 2019, $(8) million, $(5) million and $(3) million respectively was reclassified from accumulated other comprehensive income and reported in other deductions.

Warrants

At the Merger Date, the Company entered into an agreement whereby the holder of each outstanding warrant previously issued by Dynegy would be entitled to receive, upon paying an exercise, price of $35.00 (subject to adjustment from time to time), the number of shares of Vistra common stock that such holder would have been entitled to receive if it had held one share of Dynegy common stock at the closing of the Merger, or 0.652 shares of Vistra common stock. Accordingly, upon exercise, a warrant holder would effectively pay $53.68 (subject to adjustment of the exercise price from time to time) per share of Vistra common stock received. In July 2021, in accordance with the terms of the warrant agreement, the exercise price of each warrant was adjusted downward to $34.54 (subject to further adjustment from time to time), or $52.98 (subject to adjustment of the exercise price from time to time) per share of Vistra common stock received. As of December 31, 2021, nine million warrants expiring in 2024 were outstanding. The warrants were included in equity based on their fair value at the Merger Date.

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 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 (see note 11). 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 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 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 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, 2021					December 31, 2020				
	Level 1	Level 2	Level 3 (a)	Reclass (b)	Total	Level 1	Level 2	Level 3 (a)	Reclass (b)	Total
Assets:										
Commodity contracts	$ 1,408	$ 889	$ 442	$ 5	$ 2,744	$ 452	$ 201	$ 205	$ 76	$ 934
Interest rate swaps	—	19	—	—	19	—	72	—	—	72
Nuclear decommissioning trust – equity securities (c)	724	—	—	—	724	623	—	—	—	623
Nuclear decommissioning trust – debt securities (c)	—	679	—	—	679	—	618	—	—	618
Sub-total	$ 2,132	$ 1,587	$ 442	$ 5	4,166	$ 1,075	$ 891	$ 205	$ 76	2,247
Assets measured at net asset value (d):										
Nuclear decommissioning trust – equity securities (c)					557					433
Total assets					$ 4,723					$ 2,680
Liabilities:										
Commodity contracts	$ 2,153	$ 650	$ 802	$ 5	$ 3,610	$ 578	$ 172	$ 183	$ 76	$ 1,009
Interest rate swaps	—	217	—	—	217	—	404	—	—	404
Total liabilities	$ 2,153	$ 867	$ 802	$ 5	$ 3,827	$ 578	$ 576	$ 183	$ 76	$ 1,413

(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, 2021 and 2020:

December 31, 2021

	Fair Value						
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**	**Average (b)**
Electricity purchases and sales	$ 204	$ (470)	$ (266)	Income Approach	Hourly price curve shape (c)	$ — to $ 60 MWh	$ 30
					Illiquid delivery periods for hub power prices and heat rates (d)	$ 20 to $140 MWh	$ 80
Options	1	(209)	(208)	Option Pricing Model	Gas to power correlation (e)	10 % to 100 %	56 %
					Power and gas volatility (e)	5 % to 490 %	248 %
Financial transmission rights	122	(34)	88	Market Approach (f)	Illiquid price differences between settlement points (g)	$(30) to $ 10 MWh	$ (9)
Natural gas	29	(86)	(57)	Income Approach	Gas basis (h)	$ (1) to $ 16 MMBtu	$ 8
Coal	61	—	61	Income Approach	Probability of default (i)	— % to 40 %	20%
					Recovery rate (j)	— % to 40 %	20%
Other (k)	25	(3)	22				
Total	$ 442	$ (802)	$ (360)				

December 31, 2020

	Fair Value						
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**	**Average (b)**
Electricity purchases and sales	$ 61	$ (90)	$ (29)	Income Approach	Hourly price curve shape (c)	$ — to $ 85 MWh	$ 43
					Illiquid delivery periods for hub power prices and heat rates (d)	$ 25 to $125 MWh	$ 75
Options	38	(56)	(18)	Option Pricing Model	Gas to power correlation (e)	30 % to 100 %	64 %
					Power and gas volatility (e)	5 % to 665 %	336 %
Financial transmission rights	92	(16)	76	Market Approach (f)	Illiquid price differences between settlement points (g)	$ (5) to $ 50 MWh	$ 22
Natural gas	7	(14)	(7)	Income Approach	Gas basis (h)	$ (1) to $ — MMBtu	$ —
Coal	1	(5)	(4)	Income Approach	Probability of default (i)	— % to 40 %	20%
					Recovery rate (j)	— % to 40 %	20%
Other (k)	6	(2)	4				
Total	$ 205	$ (183)	$ 22				

(a) Electricity purchase and sales contracts include power and heat rate positions in ERCOT, PJM, ISO-NE, NYISO and MISO regions. The forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points are referred to as congestion revenue rights (CRRs) in ERCOT and financial transmission rights (FTRs) in PJM, ISO-NE, NYISO 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. The average represents the arithmetic average of the underlying inputs and is not weighted by the related fair value or notional amount.

(c) Primarily based on the historical range of forward average hourly ERCOT North Hub prices.

(d) Primarily based on historical forward ERCOT and PJM power prices and ERCOT heat rate variability.
(e) Primarily based on the historical forward correlation and volatility within ERCOT and PJM.
(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) Primarily based on the historical forward PJM and Northeast gas basis prices.
(i) Estimate of the range of probabilities of default based on past experience, the length of the contract, and both the Company's and the counterparty's credit ratings.
(j) Estimate of the default recovery rate based on historical corporate rates.
(k) Other includes contracts for environmental allowances.

There were no transfers between Level 1 and Level 2 of the fair value hierarchy for the years ended December 31, 2021, 2020 and 2019. See the table below for discussion of transfers between Level 2 and Level 3 for the years ended December 31, 2021, 2020 and 2019.

The following table presents the changes in fair value of the Level 3 assets and liabilities for the years ended December 31, 2021, 2020 and 2019.

	Year Ended December 31,		
	2021	2020	2019
Net asset (liability) balance at beginning of period	$ 22	$ (74)	$ (135)
Total unrealized valuation gains (losses) (a)	(53)	(5)	8
Purchases, issuances and settlements (b):			
Purchases	114	164	176
Issuances	(36)	(28)	(81)
Settlements	(314)	(90)	(64)
Transfers into Level 3 (c)	(2)	(2)	10
Transfers out of Level 3 (c)	(91)	57	12
Net change (d)	(382)	96	61
Net asset (liability) balance at end of period	$ (360)	$ 22	$ (74)
Unrealized valuation gains (losses) relating to instruments held at end of period	$ (364)	$ 18	$ (61)

(a) During the year ended December 31, 2021, includes a net loss of $341 million due to the third quarter 2021 discontinuance of normal purchase and sale accounting on a retail electric contract portfolio where physical settlement is no longer considered probable throughout the contract term.
(b) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received, including CRRs and FTRs.
(c) Includes transfers due to changes in the observability of significant inputs. All Level 3 transfers during the periods presented are in and out of Level 2. For the year ended December 31, 2021, transfers into Level 3 primarily consist of natural gas, emissions and coal derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become observable. For the year ended December 31, 2020, transfers out of Level 3 primarily consist of natural gas, power and coal derivatives where forward pricing inputs have become observable. For the year ended December 31, 2019, transfers out of Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become observable.
(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, fuel 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. During 2019, Vistra entered into $2.12 billion of new interest rate swaps, pursuant to which Vistra 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 $2.30 billion of debt through July 2026.

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, 2021 and 2020. Derivative asset and liability totals represent the net value of the contract, while the balance sheet totals represent the gross value of the contract. During the year ended December 31, 2021, a net loss of $298 million was recognized in operating revenues due to the third quarter 2021 discontinuance of normal purchase and sale accounting on a retail electric contract portfolio where physical settlement is no longer considered probable throughout the contract term. These amounts are reflected in commodity contracts derivative liabilities at December 31, 2021.

	December 31, 2021				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 2,496	$ 14	$ 3	$ —	$ 2,513
Noncurrent assets	244	5	1	—	250
Current liabilities	—	—	(2,964)	(59)	(3,023)
Noncurrent liabilities	(1)	—	(645)	(158)	(804)
Net assets (liabilities)	$ 2,739	$ 19	$ (3,605)	$ (217)	$ (1,064)

	December 31, 2020				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 665	$ 19	$ 64	$ —	$ 748
Noncurrent assets	197	53	8	—	258
Current liabilities	(1)	—	(717)	(71)	(789)
Noncurrent liabilities	(3)	—	(288)	(333)	(624)
Net assets (liabilities)	$ 858	$ 72	$ (933)	$ (404)	$ (407)

As of December 31, 2021 and 2020, there were no derivative positions accounted for as cash flow or fair value hedges.

The following table presents the pre-tax 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)	2021	2020	2019
Commodity contracts (Operating revenues)	$ (1,196)	$ 241	$ 339
Commodity contracts (Fuel, purchased power costs and delivery fees)	732	4	(1)
Interest rate swaps (Interest expense and related charges)	81	(196)	(217)
Net gain (loss)	$ (383)	$ 49	$ 121

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, 2021				December 31, 2020			
	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	$ 2,739	$ (2,051)	$ (27)	$ 661	$ 858	$ (667)	$ (11)	$ 180
Interest rate swaps	19	(19)	—	—	72	(72)	—	—
Total derivative assets	2,758	(2,070)	(27)	661	930	(739)	(11)	180
Derivative liabilities:								
Commodity contracts	(3,605)	2,051	784	(770)	(933)	667	138	(128)
Interest rate swaps	(217)	19	—	(198)	(404)	72	—	(332)
Total derivative liabilities	(3,822)	2,070	784	(968)	(1,337)	739	138	(460)
Net amounts	$ (1,064)	$ —	$ 757	$ (307)	$ (407)	$ —	$ 127	$ (280)

(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, and, to a lesser extent, initial margin requirements.

Derivative Volumes

The following table presents the gross notional amounts of derivative volumes at December 31, 2021 and 2020:

Derivative type		December 31, 2021		December 31, 2020	Unit of Measure
		Notional Volume			
Natural gas (a)		4,701		5,264	Million MMBtu
Electricity		440,236		438,863	GWh
Financial transmission rights (b)		224,876		217,350	GWh
Coal		25		20	Million U.S. tons
Fuel oil		87		176	Million gallons
Emissions		18		8	Million tons
Renewable energy certificates		32		18	Million certificates
Interest rate swaps – variable/fixed (c)	$	6,720	$	6,720	Million U.S. dollars
Interest rate swaps - fixed/variable (c)	$	2,120	$	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 regions.
(c) Includes notional amounts of interest rate swaps with maturity dates through July 2026.

Credit Risk-Related Contingent Features of Derivatives

Our derivative contracts may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements require the posting of collateral if our credit rating is downgraded by one or more credit rating agencies or include cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

The following table presents the commodity derivative liabilities subject to credit risk-related contingent features that are not fully collateralized:

	December 31, 2021	December 31, 2020
Fair value of derivative contract liabilities (a)	$ (1,200)	$ (679)
Offsetting fair value under netting arrangements (b)	660	262
Cash collateral and letters of credit	95	35
Liquidity exposure	$ (445)	$ (382)

(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. As of December 31, 2021, total credit risk exposure to all counterparties related to derivative contracts totaled $3.742 billion (including associated accounts receivable). The net exposure to those counterparties totaled $1.417 billion at December 31, 2021 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure to ERCOT totaling $619 million. As of December 31, 2021, the credit risk exposure to the banking and financial sector represented 54% of the total credit risk exposure and 4% 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 is the plan sponsor of the Vistra Retirement Plan (the Retirement Plan), which provides benefits to eligible employees of its subsidiaries. Oncor is a participant in the Retirement Plan. As Vistra accounts for its interests in the Retirement Plan as a multiple employer plan, only Vistra'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 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.

Effective January 1, 2018, Vistra 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 (or its predecessors) are split between Oncor and Vistra. As Vistra accounts for its interest in this OPEB plan as a multiple employer plan, only Vistra's share of the plan assets and obligations are reported in the OPEB information presented below. In addition, Vistra is the sponsor of OPEB plans that certain EFH Corp. and Dynegy retirees participate in.

Pension and OPEB Costs

	Year Ended December 31,		
	2021	2020	2019
Pension costs	$ 6	$ 11	$ 9
OPEB costs	8	7	11
Total benefit costs recognized as expense	$ 14	$ 18	$ 20

Market-Related Value of Assets Held in Pension 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 Plans and OPEB Benefits

The following information is based on a December 31, 2021, 2020 and 2019 measurement dates:

	Retirement Plan			OPEB Plans		
	Year Ended December 31,			Year Ended December 31,		
	2021	2020	2019	2021	2020	2019
Assumptions Used to Determine Net Periodic Pension and Benefit Cost:						
Discount rate	2.50 %	3.24 %	4.37 %	2.51 %	3.25 %	4.35 %
Expected rate of compensation increase	3.41 %	3.29 %	3.35 %			
Interest crediting rate for cash balance	3.00 %	3.50 %	3.50 %			
Expected return on plan assets (Vistra Plan)	3.77 %	4.44 %	4.80 %			
Expected return on plan assets (Dynegy Plan)	4.42 %	5.28 %	5.31 %			
Expected return on plan assets (EEI Plan)	4.72 %	5.45 %	5.56 %			
Expected return on plan assets (EEI Union)				6.79 %	7.07 %	5.36 %
Expected return on plan assets (EEI Salaried)				2.95 %	3.43 %	4.70 %
Components of Net Pension and Benefit Cost:						
Service cost	$ 5	$ 6	$ 7	$ 1	$ 2	$ 2
Interest cost	16	20	25	4	4	6
Expected return on assets	(18)	(23)	(26)	(2)	(2)	(1)
Amortization of unrecognized amounts	3	1	—	5	4	3
Immediate pension and postretirement benefit cost	—	7	3	—	(1)	1
Net periodic pension and OPEB cost	$ 6	$ 11	$ 9	$ 8	$ 7	$ 11
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:						
Net (gain) loss and prior service (credit) cost	$ (29)	$ 17	$ 11	$ (12)	$ 5	$ —
Total recognized in net periodic benefit cost and other comprehensive income	$ (23)	$ 28	$ 20	$ (4)	$ 12	$ 11
Assumptions Used to Determine Benefit Obligations at Period End:						
Discount rate	2.84 %	2.50 %	3.24 %	2.87 %	2.51 %	3.25 %
Expected rate of compensation increase	3.49 %	3.41 %	3.29 %			
Interest crediting rate for cash balance plans	3.00 %	3.00 %	3.50 %			

Net Actuarial Gains (Losses)

Retirement Plan — For the year ended December 31, 2021, the net actuarial gain of $24 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets and gains attributable to actual asset performance exceeding expectations, partially offset by losses attributable to demographic assumption updates to reflect recent plan experience, actuarial assumption updates to reflect current market conditions, plan amendments, settlements and plan experience different than expected.

For the year ended December 31, 2020, the net actuarial loss of $29 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 and plan amendments, partially offset by gains attributable to actual asset performance exceeding expectations, life expectancy updates, annuity purchases, lump sum windows and plan experience different than expected.

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.

OPEB Plans — For the year ended December 31, 2021, the net actuarial gain of $7 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets, plan experience different than expected, updates to health care claims and trend assumptions and actual asset performance exceeding expectations, partially offset by losses attributable to demographic assumption updates and life expectancy updates.

For the year ended December 31, 2020, the net actuarial loss of $10 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 updates and updates to health care claims and trend assumptions.

For the period 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.

	Retirement Plan		OPEB Plans	
	Year Ended December 31,		Year Ended December 31,	
	2021	2020	2021	2020
Change in Pension and Postretirement Benefit Obligations:				
Projected benefit obligation at beginning of period	$ 643	$ 674	$ 157	$ 151
Service cost	5	6	1	2
Interest cost	16	20	4	4
Participant contributions	—	—	3	3
Lump-sum window	—	(6)	—	—
Annuity purchase	—	(29)	—	—
Actuarial loss	(11)	46	(6)	12
Benefits paid	(48)	(68)	(13)	(15)
Projected benefit obligation at end of year	$ 605	$ 643	$ 146	$ 157
Accumulated benefit obligation at end of year	$ 600	$ 639	$ —	$ —
Change in Plan Assets:				
Fair value of assets at beginning of period	$ 485	$ 528	$ 37	$ 34
Employer contributions	1	16	9	9
Participant contributions	—	—	3	3
Lump-sum window	—	(6)	—	—
Annuity purchase	—	(29)	—	—
Actual gain on assets	30	40	3	4
Benefits paid	(46)	(64)	(13)	(13)
Fair value of assets at end of year	$ 470	$ 485	$ 39	$ 37
Funded Status:				
Projected pension benefit obligation	$ (605)	$ (643)	$ (146)	$ (157)
Fair value of assets	470	485	39	37
Funded status at end of year	$ (135)	$ (158)	$ (107)	$ (120)
Amounts Recognized in the Balance Sheet Consist of:				
Other noncurrent assets	$ —	$ —	$ 26	$ 23
Other current liabilities	—	—	(9)	(9)
Other noncurrent liabilities	(135)	(158)	(124)	(134)
Net liability recognized	$ (135)	$ (158)	$ (107)	$ (120)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:				
Net loss and prior service cost	$ (13)	$ (42)	$ 8	$ 20

Fair Value Measurement of Pension and OPEB Plan Assets

Retirement Plan — As of December 31, 2021 and 2020, all of the Retirement Plan assets were measured at fair value using the net asset value per share (or its equivalent) and consisted of the following:

	December 31, 2021	December 31, 2020
Asset Category:		
Cash commingled trusts	11	11
Equity securities:		
Global equities	149	153
Fixed income securities:		
Corporate bonds (a)	199	207
Government bonds	31	37
Other (b)	30	32
Real estate	50	45
Total assets measured at net asset value	$ 470	$ 485

(a) Substantially all corporate bonds are rated investment grade by a major ratings agency such as Moody's.
(b) Consists primarily of high-yield bonds, emerging market debt and bank loans.

OPEB Plans — As of December 31, 2021 and 2020, the Vistra OPEB plan assets measured at fair value on a recurring basis totaled $39 million and $37 million, respectively. At December 31, 2021, assets consisted of $37 million of comingled funds valued at net asset value and $2 million of municipal bond and cash equivalent mutual funds classified as Level 1. At December 31, 2020, assets consisted of $29 million of U.S. equities classified as Level 1 and $8 million of U.S. Treasuries and municipal bonds classified as Level 2.

Pension Plans with Projected Benefit Obligations (PBO) and Accumulated Benefit Obligations (ABO)

The following table provides information regarding pension plans with PBO and ABO in excess of the fair value of plan assets.

	December 31, 2021	December 31, 2020
Pension Plans with PBO and ABO in Excess Of Plan Assets:		
Projected benefit obligations	$ 605	$ 643
Accumulated benefit obligation	$ 600	$ 639
Plan assets	$ 470	$ 485

Retirement 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. Real estate and credit strategies (primarily high yield bonds and emerging market debt) provide additional portfolio diversification and return potential.

The target asset allocation ranges of pension plan investments by asset category are as follows:

	Target Allocation Ranges		
Asset Category:	**Vistra Plan**	**Dynegy Plan**	**EEI Plan**
Fixed income	65 % - 75%	45 % - 55%	40 % - 50%
Global equity securities	16 % - 24%	30 % - 38%	34 % - 42%
Real estate	4 % - 8%	8 % - 12%	10 % - 14%
Credit strategies	3 % - 7%	6 % - 10%	7 % - 11%

Retirement Plan 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 Plan	Dynegy Plan	EEI Plan
Fixed income securities	3.1 %	3.1 %	3.1 %
Global equity securities	6.9 %	6.9 %	6.9 %
Real estate	5.4 %	5.4 %	5.4 %
Credit strategies	5.5 %	5.5 %	5.5 %
Weighted average	4.2 %	4.8 %	4.9 %

Benefit Plan Assumed Health Care Cost Trend Rates

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

	December 31,	
	2021	2020
Assumed Health Care Cost Trend Rates-Not Medicare Eligible:		
Health care cost trend rate assumed for next year	6.30 %	6.20 %
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	2029
Assumed Health Care Cost Trend Rates-Medicare Eligible:		
Health care cost trend rate assumed for next year (Vistra Plan, EEI Union and EEI Salaried)	9.60 %	9.10 %
Health care cost trend rate assumed for next year (Split-Participant Plan)	8.90 %	8.80 %
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	2031	2030

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, 2021 consisted of 307 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, 2021, 2020 and 2019 totaled $1 million, $16 million and zero, respectively, and no contributions are expected to be made in 2022. OPEB plan funding for each year ended December 31, 2021, 2020 and 2019 totaled $9 million and funding in 2022 is expected to total $9 million.

Future Benefit Payments

Estimated future benefit payments to beneficiaries are as follows:

	2022	2023	2024	2025	2026	2027-2031
Pension benefits	$ 67	$ 42	$ 33	$ 34	$ 46	$ 162
OPEB	$ 10	$ 10	$ 10	$ 9	$ 9	$ 39

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 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 $34 million, $34 million and $27 million for the years ended December 31, 2021, 2020 and 2019, respectively.

18. STOCK-BASED COMPENSATION

Vistra 2016 Omnibus Incentive Plan

On the Effective Date, the Vistra 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. Following approval of the Board and approval by the stockholders at the 2019 annual meeting of the Company, the 2016 Incentive Plan was amended to increase the maximum number of shares reserved for issuance under the 2016 Incentive Plan to 37,500,000. 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 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 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 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. No awards under the 2016 Incentive Plan have been settled in cash since the Effective Date.

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 stockholders.

Stock-Based Compensation Expense

Stock-based compensation expense is reported as SG&A in the consolidated statements of operations as follows:

	Year Ended December 31,		
	2021	2020	2019
Total stock-based compensation expense	$ 51	$ 63	$ 47
Income tax benefit	(12)	(15)	(9)
Stock based-compensation expense, net of tax	$ 39	$ 48	$ 38

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 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 through 2018, and assumed 2.3% and 1.9% dividend yields in the valuation of options granted in 2020 and 2019, respectively. These options may be exercised over either three- or four-year graded vesting periods and will expire 10 years from the grant date.

Stock options outstanding at December 31, 2021 are all held by current or former employees. The following table summarizes our stock option activity:

	Year Ended December 31, 2021			
	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	16,030	$ 19.58	6.7	$ 30.8
Granted	—	$ —		
Exercised	(894)	$ 14.25		
Forfeited or expired	(1,189)	$ 28.18		
Total outstanding at end of period	13,947	$ 19.28	5.9	$ 55.7
Exercisable at December 31, 2021	7,234	$ 17.60	5.7	$ 42.1

As of December 31, 2021, $12 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 1 year.

Restricted Stock Units

The following table summarizes our restricted stock unit activity:

	Year Ended December 31, 2021	
	Restricted Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Total nonvested at beginning of period	2,252	$ 22.35
Granted	1,858	$ 22.61
Vested	(1,082)	$ 22.02
Forfeited	(217)	$ 23.20
Total nonvested at end of period	2,811	$ 22.57

As of December 31, 2021, $38 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.

We also issue Performance Stock Units (PSUs) to certain members of management on an annual basis. All PSUs have a three year performance period and a payout opportunity of 0-200% of target (100%), which is intended to be settled in shares of Vistra common stock. We recognized compensation expense associated with PSUs of $9 million, $15 million and zero for the years ended December 31, 2021, 2020 and 2019, respectively. As of December 31, 2021, we have $2 million of unrecognized compensation cost associated with PSUs.

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 RRA) with certain selling stockholders. Pursuant to the RRA, we maintain a registration statement on Form S-3 providing for registration of the resale of the Vistra common stock held by such selling stockholders. In addition, under the terms of the RRA, among other things, 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 RRA the opportunity to register all or part of their shares on the terms and conditions set forth in the RRA.

Tax Receivable Agreement

On the Effective Date, Vistra 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.

20. SEGMENT INFORMATION

The operations of Vistra are aligned into six reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. In the third quarter of 2020, Vistra updated its reportable segments to reflect changes in how the Company's Chief Operating Decision Maker (CODM) makes operating decisions, assesses performance and allocates resources. Management believes the revised reportable segments provide enhanced transparency into the Company's long-term sustainable assets and its commitment to managing the retirement of economically and environmentally challenged plants. The following is a summary of the updated segments:

- The Sunset segment represents plants with announced retirement plans that were previously reported in the ERCOT, PJM and MISO segments. Given recent and expected future retirements of certain power plants, management believes it is important to have a segment which differentiates between operating plants with defined retirement plans and operating plants without defined retirement plans.
- The East segment represents Vistra's electricity generation operations in the Eastern Interconnection of the U.S. electric grid, other than assets that are now part of the Sunset or Asset Closure segments, respectively, and includes operations in PJM, ISO-NE and NYISO that were previously reported in the PJM and NY/NE segments, respectively.
- The West segment represents Vistra's electricity generation operations in CAISO and was previously reported in the Corporate and Other non-segment. As reflected by the Moss Landing and Oakland ESS projects (see Note 3), the Company expects to expand its operations in the West segment.

Our CODM reviews the results of these segments separately and allocates resources to the respective segments as part of our strategic operations. A measure of assets is not applicable, as segment assets are not regularly reviewed by the CODM for evaluating performance or allocating resources.

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, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. Gas & Electric across 19 states in the U.S.

The Texas and East segments are engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel production and fuel logistics management. The Texas segment represents results from the ERCOT market and was referred to as the ERCOT segment prior to the third quarter of 2020. The East segment represents results from the PJM, ISO-NE and NYISO markets. We determined it was appropriate to aggregate results from these markets into one reportable segment, East, given similar economic characteristics.

The West segment represents results from the CAISO market, including our development of battery ESS projects at our Moss Landing and Oakland power plant sites (see Note 3).

The Sunset segment consists of generation plants with announced retirement plans. Separately reporting the Sunset segment differentiates operating plants with announced retirement plans from our other operating plants in the Texas, East and West segments. We have allocated unrealized gains and losses on the commodity risk management activities to the Sunset segment for the generation plants that have announced retirement plans.

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'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, 2019 and 2020.

Corporate and Other represents the remaining non-segment operations consisting primarily of general corporate expenses, interest, taxes and other expenses related to our support functions that provide shared services to our operating segments.

The accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1. Our CODM 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	Texas	East	West	Sunset	Asset Closure	Corporate and Other (b)	Eliminations	Consolidated
Operating revenues (a):									
December 31, 2021	$ 7,871	$ 2,790	$ 2,587	$ 374	$ 739	$ —	$ —	$ (2,284)	$ 12,077
December 31, 2020	8,270	4,116	2,415	282	1,252	3	—	(4,895)	11,443
December 31, 2019	6,872	3,836	2,790	338	1,602	341	—	(3,970)	11,809
Depreciation and amortization:									
December 31, 2021	$ (212)	$ (608)	$ (698)	$ (60)	$ (139)	$ —	$ (36)	$ —	$ (1,753)
December 31, 2020	(303)	(475)	(721)	(19)	(133)	(22)	(64)	—	(1,737)
December 31, 2019	(292)	(472)	(680)	(19)	(120)	—	(57)	—	(1,640)
Operating income (loss):									
December 31, 2021	$ 2,213	$ (2,601)	$ (552)	$ (8)	$ (428)	$ (56)	$ (83)	$ —	$ (1,515)
December 31, 2020	312	1,761	73	39	(420)	(109)	(137)	—	1,519
December 31, 2019	155	1,314	398	88	271	(107)	(127)	1	1,993
Interest expense and related charges:									
December 31, 2021	$ (9)	$ 14	$ (15)	$ 9	$ (2)	$ (1)	$ (381)	$ 1	$ (384)
December 31, 2020	(10)	8	(7)	10	(2)	—	(632)	3	(630)
December 31, 2019	(21)	8	(13)	—	(4)	—	(770)	3	(797)
Income tax (expense) benefit:									
December 31, 2021	$ (2)	$ —	$ —	$ —	$ —	$ —	$ 460	$ —	$ 458
December 31, 2020	—	—	—	—	—	—	(266)	—	(266)
December 31, 2019	—	—	—	—	—	—	(290)	—	(290)
Net income (loss):									
December 31, 2021	$ 2,196	$ (2,512)	$ (567)	$ 1	$ (413)	$ (22)	$ 53	$ —	$ (1,264)
December 31, 2020	309	1,760	41	50	(414)	(101)	(1,021)	—	624
December 31, 2019	134	1,342	400	88	274	(109)	(1,204)	1	926
Capital expenditures, including nuclear fuel and excluding LTSA prepayments and development and growth expenditures:									
December 31, 2021	$ 1	$ 266	$ 44	$ 8	$ 31	$ —	$ 48	$ —	$ 398
December 31, 2020	2	388	71	2	46	—	91	—	600
December 31, 2019	1	296	61	2	58	—	69	—	487

(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	Texas	East	West	Sunset	Asset Closure	Corporate and Other	Eliminations (1)	Consolidated
December 31, 2021	$ (325)	$ (1,272)	$ (637)	$ (42)	$ (634)	$ —	$ —	$ 1,719	$ (1,191)
December 31, 2020	(11)	677	(23)	(10)	(140)	—	—	(329)	164
December 31, 2019	8	575	195	41	168	—	—	(305)	682

(1) Amounts offset in fuel, purchased power costs and delivery fees in the Retail segment, with no impact to consolidated results.

(b) Income tax expense is generally not reflected in net income of the segments but is reflected almost entirely in Corporate and Other net income.

21. SUPPLEMENTARY FINANCIAL INFORMATION

Impairment of Long-Lived Assets

In the second quarter of 2021, we recognized an impairment loss of $38 million related to our Zimmer generation facility in Ohio as a result of a significant decrease in the estimated useful life of the facilities, reflecting a decrease in the economic forecast of the facility and the inability to secure capacity revenues for the plant in the latest PJM capacity auction held in May 2021. The impairments are reported in our Sunset segment and include a $33 million write-down of property, plant and equipment and a $5 million write-down of inventory.

In the third quarter of 2020, we recognized impairment losses of $173 million related to our Kincaid coal generation facility in Illinois and $99 million related to our Zimmer coal generation facility in Ohio, each as a result of a significant decrease in the estimated useful life of the facility, reflecting our recently announced plan to retire both facilities by the end of 2027 in response to the final CCR rule (see Notes 4 and 13). The impairment losses are reported in our Sunset segment and include a $260 million write-down of property, plant and equipment and a $12 million write-down of inventory.

In the first quarter of 2020, we recognized an impairment loss of $52 million related to our Joppa/EEI coal generation facility in Illinois as a result of a significant decrease in the estimated useful life of the facility, reflecting a decrease in the economic forecast of the facility and changes to the operating assumption based on lower forecasted wholesale electricity prices. We also recorded a $32 million impairment to a capacity contract which was linked in part to the Joppa/EEI facility and therefore determined to have a significant decrease in estimated useful life. The impairments are reported in our Sunset segment and include a $45 million write-down of property, plant and equipment, a $32 million write-down of intangible assets and a $7 million write-down of inventory.

In determining the fair value of the impaired assets, we equally weighted a market approach based on transactions of similar assets and an income approach discounting our projected cash flows through the respective plant retirement dates.

Interest Expense and Related Charges

	Year Ended December 31,		
	2021	2020	2019
Interest paid/accrued	$ 480	$ 467	$ 576
Unrealized mark-to-market net (gains) losses on interest rate swaps	(134)	155	220
Amortization of debt issuance costs, discounts and premiums	30	18	9
Debt extinguishment (gain) loss	1	(17)	(21)
Capitalized interest	(26)	(21)	(12)
Other	33	28	25
Total interest expense and related charges	$ 384	$ 630	$ 797

The weighted average interest rate applicable to the Vistra Operations Credit Facilities, taking into account the interest rate swaps discussed in Note 11, was 3.90%, 3.88% and 4.03% as of December 31, 2021, 2020 and 2019, respectively.

Other Income and Deductions

	Year Ended December 31,		
	2021	2020	2019
Other income:			
Insurance settlements (a)	$ 88	$ 6	$ 22
Gain on settlement of rail transportation disputes (b)	15	—	—
Sale of land (b)	9	8	—
Funds released from escrow to settle pre-petition claims of our predecessor (c)	—	—	9
Interest income	—	2	10
All other	28	18	15
Total other income	$ 140	$ 34	$ 56
Other deductions:			
Loss on disposal of investment in NELP (d)	$ —	$ 29	$ —
All other	16	13	15
Total other deductions	$ 16	$ 42	$ 15

(a) For the year ended December 31, 2021, $80 million reported in the Texas segment, $7 million reported in the Sunset segment and $1 million reported in the Corporate and Other non-segment. For the year ended December 31, 2020, $3 million reported in the Corporate and Other non-segment, $2 million reported in the Asset Closure segment and $1 million reported in the Texas segment. For the year ended December 31, 2019, reported in the Texas segment.
(b) Reported in the Asset Closure segment.
(c) Reported in the Corporate and Other non-segment.
(d) Reported in the East segment.

Restricted Cash

	December 31, 2021		December 31, 2020	
	Current Assets	Noncurrent Assets	Current Assets	Noncurrent Assets
Amounts related to remediation escrow accounts	$ 21	$ 13	$ 19	$ 19
Total restricted cash	$ 21	$ 13	$ 19	$ 19

Remediation Escrow — During the years ended December 31, 2020 and 2019, Vistra transferred asset retirement obligations related to several closed plant sites to a third-party remediation company. As part of certain transfers, Vistra deposits funds into an 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.

Trade Accounts Receivable

	December 31,	
	2021	2020
Wholesale and retail trade accounts receivable	$ 1,442	$ 1,324
Allowance for uncollectible accounts	(45)	(45)
Trade accounts receivable — net	$ 1,397	$ 1,279

Gross trade accounts receivable as of December 31, 2021 and 2020 included unbilled retail revenues of $426 million and $468 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Year Ended December 31,		
	2021	2020	2019
Allowance for uncollectible accounts receivable at beginning of period (a)	$ 45	$ 42	$ 19
Increase for bad debt expense	110	110	82
Decrease for account write-offs	(110)	(107)	(65)
Allowance for uncollectible accounts receivable at end of period	$ 45	$ 45	$ 36

(a) The beginning balance in 2020 includes a $6 million increase recorded due to the adoption of ASU 2016-13, *Financial Instruments—Credit Losses* (see Note 1).

Inventories by Major Category

	December 31,	
	2021	2020
Materials and supplies	$ 260	$ 260
Fuel stock	314	236
Natural gas in storage	36	19
Total inventories	$ 610	$ 515

Investments

	December 31,	
	2021	2020
Nuclear plant decommissioning trust	$ 1,960	$ 1,674
Assets related to employee benefit plans (Note 17)	42	41
Land	44	44
Miscellaneous other	3	—
Total investments	$ 2,049	$ 1,759

Investment in Unconsolidated Subsidiary

On the Merger Date, we assumed Dynegy's 50% interest in NELP, a joint venture with NextEra Energy, Inc., which indirectly owned the Bellingham NEA facility and the Sayreville facility.

In December 2019, Dynegy Northeast Generation GP, Inc. and Dynegy Northeast Associates LP, Inc., indirect subsidiaries of Vistra, entered into a transaction agreement with NELP and certain indirect subsidiaries of NextEra Energy, Inc. wherein the indirect subsidiaries of Vistra redeemed their ownership interest in NELP in exchange for 100% ownership interest in NJEA, the company which owns the Sayreville facility. The NELP Transaction was approved by FERC in February 2020, and the NELP Transaction closed on March 2, 2020. As a result of the NELP Transaction, Vistra indirectly owns 100% of the Sayreville facility and no longer has any ownership interest in the Bellingham NEA facility. A loss of $29 million was recognized in connection with the NELP Transaction, reflecting the difference between our derecognized investment in NELP and the value of our acquired 100% interest in NJEA, which was measured in accordance with ASC 805. The loss is reported in our consolidated statements of operations in other deductions.

Equity earnings related to our investment in NELP totaled $3 million and $14 million for the years ended December 31, 2020 and 2019, respectively, recorded in equity in earnings of unconsolidated investment in our consolidated statements of operations. We received distributions totaling $3 million and $22 million for the years ended December 31, 2020 and 2019, respectively.

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 (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, provided that Vistra 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,	
	2021	2020
Debt securities (a)	$ 679	$ 618
Equity securities (b)	1,281	1,056
Total	$ 1,960	$ 1,674

(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 2.54% and 2.91% as of December 31, 2021 and 2020, respectively, and an average maturity of 10 years as of both December 31, 2021 and 2020.
(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 as of December 31, 2021 mature as follows: $247 million in one to five years, $190 million in five to 10 years and $242 million after 10 years.

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

	Year Ended December 31,		
	2021	2020	2019
Proceeds from sales of securities	$ 483	$ 433	$ 431
Investments in securities	$ (505)	$ (455)	$ (453)

Property, Plant and Equipment

	December 31,	
	2021	2020
Power generation and structures	$ 16,195	$ 15,222
Land	608	617
Office and other equipment	183	173
Total	16,986	16,012
Less accumulated depreciation	(4,801)	(3,614)
Net of accumulated depreciation	12,185	12,398
Finance lease right-of-use assets (net of accumulated depreciation)	173	182
Nuclear fuel (net of accumulated amortization of $125 million and $91 million)	212	207
Construction work in progress	486	712
Property, plant and equipment — net	$ 13,056	$ 13,499

Depreciation expenses totaled $1.478 billion, $1.377 billion and $1.300 billion for the years ended December 31, 2021, 2020 and 2019, 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 32 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. As of December 31, 2021 and 2020, asbestos removal liabilities totaled $3 million and zero million, respectively. We have also identified conditional AROs for asbestos removal and disposal, which are specific to certain generation assets.

As of December 31, 2021, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.635 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 $325 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, 2021, 2020 and 2019:

	Nuclear Plant Decommissioning	Mining Land Reclamation	Coal Ash and Other	Total
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 (a)	—	—	(135)	(135)
Liability at December 31, 2019	1,320	410	508	2,238
Additions:				
Accretion	46	20	23	89
Adjustment for change in estimates (b)	219	(6)	25	238
Reductions:				
Payments	—	(65)	(49)	(114)
Liability transfers (a)	—	—	(15)	(15)
Liability at December 31, 2020	1,585	359	492	2,436
Additions:				
Accretion	50	16	22	88
Adjustment for change in estimates	—	13	1	14
Reductions:				
Payments	—	(68)	(20)	(88)
Liability at December 31, 2021	1,635	320	495	2,450
Less amounts due currently	—	(90)	(14)	(104)
Noncurrent liability at December 31, 2021	$ 1,635	$ 230	$ 481	$ 2,346

(a) 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.

(b) The adjustment for nuclear plant decommissioning resulted from a new cost estimate completed in 2020. Under applicable accounting standards, the liability is remeasured when significant changes in the amount or timing of cash flows occur, and the PUCT requires a new cost estimate at least every five years. The increase in the liability was driven by changes in assumptions including increased costs for labor, equipment and services and a delay in timing of when the U.S. Department of Energy is estimated to begin accepting spent fuel offsite.

Other Noncurrent Liabilities and Deferred Credits

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

	December 31,	
	2021	2020
Retirement and other employee benefits (Note 17)	$ 276	$ 312
Winter Storm Uri impact (a)	261	—
Identifiable intangible liabilities (Note 6)	147	289
Regulatory liability	325	89
Finance lease liabilities	235	206
Uncertain tax positions, including accrued interest	13	12
Liability for third-party remediation	17	31
Accrued severance costs	39	54
Other accrued expenses	176	138
Total other noncurrent liabilities and deferred credits	$ 1,489	$ 1,131

(a) Includes the allocation of ERCOT default uplift charges and future bill credits related to large commercial and industrial customers that curtailed during Winter Storm Uri.

Fair Value of Debt

		December 31, 2021		December 31, 2020	
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	$ 2,549	$ 2,518	$ 2,579	$ 2,565
Vistra Operations Senior Notes	Level 2	7,880	8,193	6,634	7,204
Forward Capacity Agreements	Level 3	211	211	45	45
Equipment Financing Agreements	Level 3	85	85	59	59
Building Financing	Level 2	3	3	10	10
Other debt	Level 3	3	3	3	3

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 consolidated balance sheets at December 31, 2021 and 2020:

	December 31,	
	2021	2020
Cash and cash equivalents	$ 1,325	$ 406
Restricted cash included in current assets	21	19
Restricted cash included in noncurrent assets	13	19
Total cash, cash equivalents and restricted cash	$ 1,359	$ 444

The following table summarizes our supplemental cash flow information for the years ended December 31, 2021, 2020 and 2019, respectively.

	Year Ended December 31,		
	2021	2020	2019
Cash payments related to:			
Interest paid	$ 482	$ 503	$ 525
Capitalized interest	(26)	(21)	(12)
Interest paid (net of capitalized interest)	$ 456	$ 482	$ 513
Income taxes paid / (refunds received) (a)	$ (50)	$ (140)	$ (76)
Noncash investing and financing activities:			
Accrued property, plant and equipment additions (b)	$ 171	$ 19	$ 67
Disposition of investment in NELP	$ —	$ 123	$ —
Acquisition of investment in NJEA	$ —	$ 90	$ —
Shares issued for tangible equity unit contracts (Note 14)	$ —	$ —	$ 446
Land transferred with liability transfers	$ —	$ —	$ 16

(a) For the years ended December 31, 2021, 2020 and 2019, we paid state income taxes of $52 million, $40 million and $42 million, respectively, received federal tax refunds of zero, $170 million and $115 million, respectively, and received state tax refunds of $2 million, $10 million and $3 million, respectively.

(b) Represents property, plant and equipment accruals during the period for which cash has not been paid as of the end of the period.

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, 2021. 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.

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 CORP.
MANAGEMENT'S ANNUAL REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Vistra 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 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 Corp. performed an evaluation of the effectiveness of the company's internal control over financial reporting as of December 31, 2021 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, 2021 Vistra Corp.'s internal control over financial reporting was effective.

The independent registered public accounting firm of Deloitte & Touche LLP as auditors of the consolidated financial statements of Vistra Corp. has issued an attestation report on Vistra Corp.'s internal control over financial reporting.

/s/ CURTIS A. MORGAN	/s/ JAMES A. BURKE
Curtis A. Morgan	James A. Burke
Chief Executive Officer	President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

February 25, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Vistra Corp.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Vistra Corp. and its subsidiaries (the "Company") as of December 31, 2021, 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, 2021, 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, 2021, of the Company and our report dated February 25, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying 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 25, 2022

Item 9B. OTHER INFORMATION

On February 23, 2022, our board of directors (Board) approved our amended and restated bylaws (A&R Bylaws) effective immediately. The A&R Bylaws were amended and restated, among other things, to amend advance notice requirements for stockholders to bring proposed director nominees or other items of business before a special or annual stockholders meeting, and to allow annual meetings of stockholders to be held by means of remote communication in addition to being held at any place, as determined by our Board in its sole discretion. The A&R Bylaws also reflect other technical and administrative changes.

The foregoing description of our A&R Bylaws is qualified in its entirety by the full text of the A&R Bylaws, a copy of which is included as Exhibit 3.5 to this Annual Report on Form 10-K.

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Code of Ethics

Vistra has adopted a code of ethics entitled "Vistra Code of Conduct" that applies to directors, officers and employees, including the chief executive officer and senior financial officers of Vistra. It may be accessed through the "Corporate Governance" section of the Company's website at *www.vistracorp.com*. Vistra 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 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 Definitive Proxy Statement for its 2022 Annual Meeting of Stockholders.

Item 11. EXECUTIVE COMPENSATION

Information required by this Item is incorporated by reference to the similarly named section of Vistra's Definitive Proxy Statement for its 2022 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's Definitive Proxy Statement for its 2022 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's Definitive Proxy Statement for its 2022 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's Definitive Proxy Statement for its 2022 Annual Meeting of Stockholders.

Deloitte & Touche LLP's PCAOB ID Number is 34.

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) **SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT**

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS
(Millions of Dollars)

	Year Ended December 31,		
	2021	2020	2019
Depreciation and amortization	$ (17)	$ (15)	$ (7)
Selling, general and administrative expenses	(53)	(72)	(62)
Operating loss	(70)	(87)	(69)
Other income	3	5	12
Interest expense and related charges	—	(7)	(88)
Impacts of Tax Receivable Agreement	53	5	(37)
Loss before income tax benefit	(14)	(84)	(182)
Income tax benefit	4	25	42
Equity in earnings of subsidiaries, net of tax	(1,264)	695	1,068
Net income (loss)	$ (1,274)	$ 636	$ 928

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2021	2020	2019
Cash flows — operating activities:			
Cash used in operating activities	$ (38)	$ (86)	$ (58)
Cash flows — investing activities:			
Capital expenditures	—	(15)	(36)
Dividend received from subsidiaries	405	1,105	3,890
Equity contribution to subsidiaries	(988)	—	—
Cash provided by investing activities	(583)	1,090	3,854
Cash flows — financing activities:			
Issuances of preferred stock	2,000	—	—
Repayments/repurchases of debt	—	(747)	(2,903)
Debt tender offer and other debt financing fees	—	(17)	(123)
Stock repurchases	(471)	—	(656)
Dividends paid to stockholders	(290)	(266)	(243)
Other, net	(23)	—	—
Cash used in financing activities	1,216	(1,030)	(3,925)
Net change in cash, cash equivalents and restricted cash	595	(26)	(129)
Cash, cash equivalents and restricted cash — beginning balance	73	99	228
Cash, cash equivalents and restricted cash — ending balance	$ 668	$ 73	$ 99

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(Millions of Dollars)

	December 31, 2021	December 31, 2020
ASSETS		
Cash and cash equivalents	$ 668	$ 73
Trade accounts receivable — net	8	7
Income taxes receivable	15	—
Prepaid expense and other current assets	1	5
Total current assets	692	85
Investment in affiliated companies	7,157	8,005
Property, plant and equipment — net	3	3
Identifiable intangible assets — net	31	47
Accumulated deferred income taxes	1,016	783
Other noncurrent assets	1	2
Total assets	$ 8,900	$ 8,925
LIABILITIES AND EQUITY		
Trade accounts payable	$ 114	$ 2
Accounts payable —affiliates	72	74
Accrued taxes	—	14
Other current liabilities	3	4
Total current liabilities	189	94
Tax Receivable Agreement obligations	394	447
Other noncurrent liabilities and deferred debits	25	23
Total liabilities	608	564
Total stockholders' equity	8,292	8,361
Total liabilities and equity	$ 8,900	$ 8,925

See Notes to the Condensed Financial Statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

The accompanying unconsolidated condensed balance sheets, statements of net loss and cash flows present results of operations and cash flows of Vistra Corp. (Parent). Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. GAAP have been omitted pursuant to the rules of the SEC. Because the unconsolidated condensed financial statements do not include all of the information and footnotes required by U.S. GAAP, they should be read in conjunction with the financial statements and related notes of Vistra Corp. and Subsidiaries included in the annual report on Form 10-K for the year ended December 31, 2020. Vistra Corp.'s subsidiaries have been accounted for under the equity method. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

Vistra Corp. (Parent) files a consolidated U.S. federal income tax return. Consolidated tax expenses or benefits and deferred tax assets or liabilities have been allocated to the respective subsidiaries in accordance with the accounting rules that apply to separate financial statements of subsidiaries.

2. RESTRICTIONS ON SUBSIDIARIES

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, 2021, Vistra Operations can distribute approximately $7.3 billion to Vistra Corp. (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 Vistra Corp. (Parent) of approximately $405 million, $1.1 billion and $3.9 billion during the years ended December 31, 2021, 2020 and 2019, respectively. Additionally, Vistra Operations may make distributions to Vistra Corp. (Parent) in amounts sufficient for Vistra Corp. (Parent) to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Vistra Corp. (Parent)'s ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2021, all of the restricted net assets of Vistra Operations may be distributed to Vistra Corp. (Parent).

3. GUARANTEES

Vistra Corp. (Parent) has entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2021, there are no material outstanding claims related to guarantee obligations of Vistra Corp. (Parent), and Vistra Corp. (Parent) does not anticipate it will be required to make any material payments under these guarantees in the near term.

4. DIVIDEND RESTRICTIONS

Under applicable law, Vistra Corp. (Parent) is prohibited from paying any dividend to the extent that immediately following payment of such dividend there would be no statutory surplus or Vistra Corp. (Parent) would be insolvent.

Vistra Corp. (Parent) received $405 million, $1.105 billion and $3.890 billion in dividends from its consolidated subsidiaries in the years ended December 31, 2021, 2020 and 2019, respectively. In the year ended December 31, 2021, Vistra Corp. (Parent) made an equity contribution to Vistra Operation of $988 million.

(c) EXHIBITS:

Vistra Corp. Exhibits to Form 10-K for the Fiscal Year Ended December 31, 2021

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. (now known as Vistra Corp.) and Dynegy, Inc.
(3(i))	**Articles of Incorporation**			
3.1	001-38086 Form 8-K (filed May 4, 2020)	3.1	—	Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.)
3.2	001-38086 Form 8-K (filed June 29, 2020)	3.1	—	Certificate of Amendment of the Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.), effective July 2, 2020
3.3	001-38086 Form 8-K (filed on October 15, 2021)	3.1	—	Series A Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on October 14, 2021
3.4	001-38086 Form 8-K (filed on December 13, 2021)	3.1	—	Series B Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on December 9, 2021
(3(ii))	**By-laws**			

Exhibits	Previously Filed With File Number*	As Exhibit		
3.5	**		—	Amended and Restated Bylaws of Vistra Corp., effective February 23, 2022
(4)	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	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
4.2	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)
4.3	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)
4.4	001-38086 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
4.5	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	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
4.6	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.5	—	Third Supplemental Indenture for the 5.500% Senior Notes due 2026, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.7	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.6	—	Fourth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.8	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.8	—	Fifth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.9	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.9	—	Sixth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.10	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.3	—	Seventh Supplemental Indenture for the 5.500% Senior Notes due 2026, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.11	**		—	Eighth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.12	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
4.13	001-38086 Form 8-K (filed on February 6, 2019)	4.2	—	Form of Rule 144A Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.14	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)
4.15	001-38086 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
4.16	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	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
4.17	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.7	—	Third Supplemental Indenture for the 5.625% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.18	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.8	—	Fourth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.19	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.17	—	Fifth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.20	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.18	—	Sixth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.21	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.4	—	Seventh Supplemental Indenture for the 5.625% Senior Notes due 2027, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.22	**		—	Eighth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.23	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
4.24	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)
4.25	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)
4.26	001-38086 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
4.27	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	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

Exhibits	Previously Filed With File Number*	As Exhibit		
4.28	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.9	—	Third Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.29	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.10	—	Fourth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.30	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.26	—	Fifth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.31	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.27	—	Sixth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.32	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.5	—	Seventh Supplemental Indenture for the 5.000% Senior Notes due 2027, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.33	**		—	Eighth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.34	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, and Wilmington Trust, National Association, as Trustee
4.35	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
4.36	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)
4.37	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)
4.38	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)
4.39	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)
4.40	001-38086 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
4.41	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

Exhibits	Previously Filed With File Number*	As Exhibit		
4.42	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
4.43	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)
4.44	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)
4.45	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.11	—	Fifth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of January 31, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.46	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.12	—	Sixth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of March 26, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.47	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.41	—	Seventh Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of October 7, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.48	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.42	—	Eighth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of January 8, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.49	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.6	—	Ninth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.50	**		—	Tenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.51	001-38086 Form 8-K (filed on May 11, 2021)	4.1	—	Indenture for 4.375% Senior Notes due 2029, dated as of May 10, 2021, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.52	001-38086 Form 8-K (filed on May 11, 2021)	4.2	—	Form of Rule 144A Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.53	001-38086 Form 8-K (filed on May 11, 2021)	4.3	—	Form of Regulation S Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.54	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.7	—	First Supplemental Indenture for the 4.375% Senior Notes due 2029, dated July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.55	**		—	Second Supplemental Indenture for the 4.375% Senior Notes due 2029, dated December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.56	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
4.57	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
4.58	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
4.59	001-38086 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
4.60	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
4.61	001-38086 Form 8-K (filed on October 16, 2020)	4.1	—	Fourth Amendment to Purchase and Sale Agreement, dated as of October 9, 2020, among TXU Energy Retail Company LLC, as an originator and servicer, the other originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.62	001-38086 Form 8-K (filed on December 28, 2020)	4.1	—	Fifth Amendment to Purchase and Sale Agreement, dated as of December 21, 2020, among TXU Energy Retail Company LLC, certain originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.63	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
4.64	001-38086 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
4.65	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

Exhibits	Previously Filed With File Number*	As Exhibit		
4.66	001-38086 Form 8-K (filed on July 16, 2020)	4.1	—	Fifth Amendment to Receivables Purchase Agreement, dated as of July 13, 2020, 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
4.67	001-38086 Form 8-K (filed on October 16, 2020)	4.2	—	Sixth Amendment to Receivables Purchase Agreement, dated as of October 9, 2020, 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
4.68	001-38086 Form 8-K (filed on December 28, 2020)	4.2	—	Seventh Amendment to Receivables Purchase Agreement, dated as of December 21, 2020, 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
4.69	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.56	—	Eighth Amendment to Receivables Purchase Agreement, dated as of February 19, 2020, 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
4.70	001-38086 Form 10-Q (Quarter ended March 31, 2021) (filed on May 4, 2021)	4.6	—	Ninth Amendment to Receivables Purchase Agreement, dated as of March 26, 2021, 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
4.71	001-38086 Form 8-K (filed on July 15, 2021)	4.1	—	Tenth Amendment to Receivables Purchase Agreement, dated as of July 9, 2021, 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
4.72	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.2	—	Eleventh Amendment to Receivables Purchase Agreement, dated as of July 16, 2021, 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
4.73	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
4.74	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
4.75	001-33443 Form of 8-K (filed on February 7, 2017)	4.1	—	Form of Warrant
4.76	333-215288 Form S-1 (filed December 23, 2016)	4.1	—	Registration Rights Agreement, by and among TCEH Corp. (now known as Vistra Corp.) and the Holders party thereto, dated as of October 3, 2016
4.77	**		—	Description of Capital Stock
(10)	**Material Contracts**			

Exhibits	Previously Filed With File Number*	As Exhibit		
	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 (pre-2021 awards)
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 (pre-2021 awards)
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 (pre-2021 awards)
10.5	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.5	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.6	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.6	—	Form of Restricted Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.7	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.7	—	Form of Restricted Stock Unit Award Agreement (Director) for 2016 Omnibus Incentive Plan
10.8	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.8	—	Form of Performance Stock Unit Award Agreement for 2016 Omnibus Incentive Plan
10.9	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.9	—	Vistra Corp. Executive Annual Incentive Plan
10.10	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
10.11	001-33443 Form10-K (Year ended December 31, 2018) (filed on February 28, 2019)	10.7	—	Vistra Equity Deferred Compensation Plan for Certain Directors, effective as of January 1, 2019
10.12	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.13	—	Amendment No. 1 to the Vistra Equity Deferred Compensation Plan, dated effective as of February 24, 2021
10.13	001-38086 Form 8-K (filed May 4, 2018)	10.1	—	Amended and Restated Employment Agreement, dated as of May 1, 2018, between Curtis A. Morgan and Vistra Energy Corp. (now known as Vistra Corp.)

Exhibits	Previously Filed With File Number*	As Exhibit		
10.14	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. (now known as Vistra Corp.)
10.15	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. (now known as Vistra Corp.)
10.16	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. (now known as Vistra Corp.)
10.17	001-38086 Form 8-K (filed February 27, 2020)	10.2	—	Employment Agreement between Scott A. Hudson, Vistra Energy Corp. (now known as Vistra Corp.) and TXU Retail Service Company
10.18	001-38086 Form 8-K (filed February 27, 2020)	10.1	—	Employment Agreement between Stephen J. Muscato, Vistra Energy Corp. (now known as Vistra Corp.) and Luminant Energy Company LLC
10.19	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.26	—	Form of indemnification agreement with directors
10.20	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 Corp.) and Curtis A. Morgan
10.21	**Credit Agreements and Related Agreements**			
	333-215288 Form S-1 (filed December 23, 2016)	10.1	—	Credit Agreement, dated as of October 3, 2017
10.22	333-215288 Form S-1 (filed December 23, 2016)	10.2	—	Amendment to Credit Agreement, dated December 14, 2016, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.23	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.
10.24	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.
10.25	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.
10.26	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.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.27	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.
10.28	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.
10.29	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
10.30	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
10.31	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
10.32	001-38086 Form 8-K (filed on August 7, 2018)	10.1	—	Purchase Agreement, dated August 7, 2018, by and among Vistra Operations Company LLC and Citigroup Global Markets Inc., on behalf of itself and the several Initial Purchasers named in Schedule I to the Purchase Agreement
10.33	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
10.34	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
10.35	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
10.36	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

Exhibits	Previously Filed With File Number*	As Exhibit		
10.37	001-38086 Form 8-K (filed on May 11, 2021)	10.1	—	Purchase Agreement, dated May 5, 2021, 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
10.38	001-38086 Form 8-K (filed on October 15, 2021)	10.1	—	Purchase Agreement, dated October 12, 2021, by and between Vistra Corp. and Goldman Sachs & Co. LLC
10.39	001-38086 Form 8-K (filed on December 13, 2021)	10.1	—	Purchase Agreement, dated December 7, 2021, by and between Vistra Corp. and Goldman Sachs & Co. LLC
10.40	001-38086 Form 8-K (filed on April 2, 2021)	10.1	—	Credit Agreement, dated as of March 29, 2021, among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), Royal Bank of Canada (as Administrative Agent and as Collateral Agent), and the 2021 Incremental Term Loan Lender (as defined therein)
10.41	001-38086 Form 8-K (filed on April 2, 2021)	10.2	—	First Amendment to Credit Agreement, dated as of April 1, 2021, among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), Royal Bank of Canada (as Administrative Agent and as Collateral Agent), and the 2021 Incremental Term Loan Lender (as defined therein)
10.42	001-38086 Form 8-K (filed on April 9, 2018)	10.10	—	Assumption Agreement, dated as of April 9, 2018, between Vistra Energy Corp. (now known as Vistra Corp.) (as successor by merger to Dynegy Inc.), and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent and as Collateral Trustee.
10.43	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).
10.44	001-38086 Form 8-K (filed on April 9, 2018)	10.12	—	Joinder, dated as of April 9, 2018, among Vistra Energy Corp. (now known as Vistra Corp.), the subsidiary guarantors party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee.
10.45	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).
10.46	**Other Material Contracts**			
	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
10.47	001-38086 Form 8-K (filed on June 15, 2018)	10.2	—	Amendment to Collateral Trust Agreement, effective as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as first-out representative, and Credit Suisse AG, Cayman Islands Branch, as senior credit agreement agent, and Delaware Trust Company, as Collateral Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
10.48	001-38086 Form 8-K (filed on June 15, 2018)	10.3	—	Collateral Trust Joinder, dated June 14, 2018, between the Additional Grantors party thereto and Delaware Trust Company, as Collateral Trustee, to the Collateral Trust Agreement, effective pursuant to the Seventh Amendment as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as First-Out Representative, Credit Suisse AG, Cayman Islands Branch, as Senior Credit Agreement Agent, and Delaware Trust Company, as Collateral Trustee.
10.49	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 Corp.) and American Stock Transfer & Trust Company, as transfer agent, dated as of October 3, 2016
10.50	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 Corp.), EFH Corp., Energy Future Intermediate Holding Company LLC, EFI Finance Inc. and EFH Merger Co. LLC, dated as of October 3, 2016
10.51	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
10.52	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 Corp.) and TEX Operations Company LLC (now known as Vistra Operations LLC), dated as of October 3, 2016
10.53	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
10.54	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
10.55	001-38086 Form 8-K (filed July 7, 2017)	10(a)	—	Asset Purchase Agreement, dated as of July 5, 2017, by and among Odessa-Ector Power Partners, L.P., La Frontera Holdings, LLC, Vistra Operations Company LLC, Koch Resources, LLC
10.56	001-38086 Form 8-K (filed on October 16, 2020)	10.1	—	Master Framework Agreement, dated as of October 9, 2020, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, and MUFG Bank, Ltd., as buyer
10.57	001-38086 Form 8-K (filed on July 15, 2021)	10.1	—	Amendment No. 1 to Master Framework Agreement, dated as of July 1, 2021, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.58	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	10.2	—	Amendment No. 2 to Master Framework Agreement, dated as of August 3, 2021, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.59	001-38086 Form 8-K (filed on October 16, 2020)	10.2	—	Master Repurchase Agreement, dated as of October 9, 2020, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.60	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	10.3	—	Amendment No. 1 to Master Repurchase Agreement, dated as of August 3, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.61	001-38086 Form 8-K (filed on December 28, 2020)	10.1	—	Joinder Agreement, dated as of December 21, 2020, among TXU Energy Retail company LLC, as seller party agent, Vistra Operations Company LLC, as guarantor, certain originators named therein, and MUFG Bank, Ltd., as buyer
10.62	**		—	Amendment No. 2 to Master Repurchase Agreement, dated as of December 30, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.63	**		—	Credit Agreement, dated as of February 4, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto.
(21)	**Subsidiaries of the Registrant**			
21.1	**		—	Significant Subsidiaries of Vistra 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 Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	**		—	Certification of James A. Burke, principal financial officer of Vistra Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32)	**Section 1350 Certifications**			
32.1	***		—	Certification of Curtis A. Morgan, principal executive officer of Vistra 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 James A. Burke, principal financial officer of Vistra 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 Corp.'s Annual Report on Form 10-K for the period ended December 31, 2021 formatted in Inline XBRL (Extensible Business Reporting Language) includes: (i) the Consolidated Statements of Operations, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statement of Changes in Equity and (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

Exhibits	Previously Filed With File Number*	As Exhibit		
104			—	The Cover Page Interactive Data File does not appear in Exhibit 104 because its XBRL tags are embedded within the Inline XBRL document.

* 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 Corp. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VISTRA CORP.

Date: February 25, 2022

By /s/ CURTIS A. MORGAN

Curtis A. Morgan (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 Corp. and in the capacities and on the date indicated.

Signature	Title	Date
/s/ CURTIS A. MORGAN (Curtis A. Morgan, Chief Executive Officer)	Principal Executive Officer and Director	February 25, 2022
/s/ JAMES A. BURKE (James A. Burke, President and Chief Financial Officer)	Principal Financial Officer	February 25, 2022
/s/ CHRISTY DOBRY (Christy Dobry, Senior Vice President and Controller)	Principal Accounting Officer	February 25, 2022
/s/ SCOTT B. HELM (Scott B. Helm, Chairman of the Board)	Chairman of the Board and Director	February 25, 2022
/s/ HILARY E. ACKERMANN (Hilary E. Ackermann)	Director	February 25, 2022
/s/ ARCILIA C. ACOSTA (Arcilia C. Acosta)	Director	February 25, 2022
/s/ GAVIN R. BAIERA (Gavin R. Baiera)	Director	February 25, 2022
/s/ PAUL M. BARBAS (Paul M. Barbas)	Director	February 25, 2022
/s/ LISA CRUTCHFIELD (Lisa Crutchfield)	Director	February 25, 2022
/s/ BRIAN K. FERRAIOLI (Brian K. Ferraioli)	Director	February 25, 2022
/s/ JEFF D. HUNTER (Jeff D. Hunter)	Director	February 25, 2022
/s/ JOHN R. SULT (John R. Sult)	Director	February 25, 2022

INFORMATION FOR STOCKHOLDERS

Stock Exchange Listing

NYSE: VST

Corporate Headquarters

Vistra 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'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. 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 investor relations contact details, are available on our website at www.vistracorp.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

John R. Sult (1,2)

[1] Audit Committee

[2] Social Responsibility and Compensation Committee

[3] Nominating and Governance Committee

[4] Sustainability and Risk Committee

* Committee Chair

† As of April 4, 2022. Besides Curtis A. Morgan, all members of the Vistra Board of Directors satisfy the independence requirements of the Securities and Exchange Commission and the NYSE.

VISTRA

6555 Sierra Drive, Irving, Texas 75039 | www.vistracorp.com