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, 2022

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: 001-35081

Kinder Morgan, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**80-0682103**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

1001 Louisiana Street, Suite 1000, Houston, Texas 77002

(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 713-369-9000

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class P Common Stock	KMI	New York Stock Exchange
2.250% Senior Notes due 2027	KMI 27 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 ☐

Indicate 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," "non-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. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2022 was approximately $33,112,481,840. As of February 7, 2023, the registrant had 2,248,003,224 shares of Class P common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023, are incorporated into PART III, as specifically set forth in PART III.

KINDER MORGAN, INC. AND SUBSIDIARIES
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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

Calnev	=	Calnev Pipe Line LLC	KMLT	=	Kinder Morgan Liquid Terminals, LLC
CIG	=	Colorado Interstate Gas Company, L.L.C.	KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and/or controlled subsidiaries
CPGPL	=	Cheyenne Plains Gas Pipeline Company, L.L.C.			
EagleHawk	=	EagleHawk Field Services LLC	KMTP	=	Kinder Morgan Texas Pipeline LLC
Elba Express	=	Elba Express Company, L.L.C.	MEP	=	Midcontinent Express Pipeline LLC
EIG	=	EIG Global Energy Partners	NGPL	=	Natural Gas Pipeline Company of America LLC and certain affiliates
ELC	=	Elba Liquefaction Company, L.L.C.			
EPNG	=	El Paso Natural Gas Company, L.L.C.	PHP	=	Permian Highway Pipeline LLC
FEP	=	Fayetteville Express Pipeline LLC	Ruby	=	Ruby Pipeline Holding Company, L.L.C.
Hiland	=	Hiland Partners, LP	SFPP	=	SFPP, L.P.
KinderHawk	=	KinderHawk Field Services LLC	SLNG	=	Southern LNG Company, L.L.C.
Kinetrex	=	Kinetrex Energy	SNG	=	Southern Natural Gas Company, L.L.C.
KMBT	=	Kinder Morgan Bulk Terminals, Inc.	Stagecoach	=	Stagecoach Gas Services LLC
KMI	=	Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries	TGP	=	Tennessee Gas Pipeline Company, L.L.C.
			WIC	=	Wyoming Interstate Company, L.L.C.
KMLP	=	Kinder Morgan Louisiana Pipeline LLC	WYCO	=	WYCO Development L.L.C.

Unless the context otherwise requires, references to "we," "us," "our," or "the Company" are intended to mean Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries.

Common Industry and Other Terms

/d	=	per day	GAAP	=	United States Generally Accepted Accounting Principles
AFUDC	=	allowance for funds used during construction			
Bbl	=	barrels	GTE	=	gas-to-electric
BBtu	=	billion British Thermal Units	LIBOR	=	London Interbank Offered Rate
Bcf	=	billion cubic feet	LLC	=	limited liability company
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act	LNG	=	liquefied natural gas
			MBbl	=	thousand barrels
CO_2	=	carbon dioxide or our CO_2 business segment	MMBbl	=	million barrels
COVID-19	=	Coronavirus Disease 2019, a widespread contagious disease, or the related pandemic declared and resulting worldwide economic downturn	MMtons	=	million tons
			NGL	=	natural gas liquids
			NYMEX	=	New York Mercantile Exchange
CPUC	=	California Public Utilities Commission	NYSE	=	New York Stock Exchange
DCF	=	distributable cash flow	OTC	=	over-the-counter
DD&A	=	depreciation, depletion and amortization	PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
Dth	=	dekatherms			
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	ROU	=	Right-of-Use
			RNG	=	renewable natural gas
EBITDA	=	earnings before interest, income taxes, depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	SEC	=	United States Securities and Exchange Commission
			SOFR	=	Secured Overnight Financing Rate
EPA	=	United States Environmental Protection Agency	U.S.	=	United States of America
FASB	=	Financial Accounting Standards Board	WTI	=	West Texas Intermediate
FERC	=	Federal Energy Regulatory Commission			

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “outlook,” “continue,” “estimate,” “expect,” “may,” “will,” “shall,” or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow, service debt or pay dividends, are forward-looking statements. Forward-looking statements in this report include, among others, express or implied statements pertaining to: the long-term demand for our assets and services, and our anticipated dividends and capital projects, including expected completion timing and benefits of those projects.

Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results may differ materially from those expressed in our forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or accurately predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- changes in supply of and demand for natural gas, NGL, refined petroleum products, oil, renewable fuels, CO_2, electricity, petroleum coke, steel and other bulk materials and chemicals and certain agricultural products in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- competition from other pipelines, terminals or other forms of transportation, or from emerging technologies such as CO_2 capture and sequestration;
- changes in our tariff rates required by the FERC, the CPUC or another regulatory agency;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts at economically attractive rates;
- our ability to safely operate and maintain our existing assets and to access or construct new assets including pipelines, terminals, gas processing, gas storage and NGL fractionation capacity;
- our ability to attract and retain key management and operations personnel;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- shut-downs or cutbacks at major refineries, chemical or petrochemical plants, natural gas processing plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production (and the NGL content of natural gas production) from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the shale plays in North Dakota, Ohio, Oklahoma, Pennsylvania and Texas, and the U.S. Rocky Mountains;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may increase our compliance costs, restrict our ability to provide or reduce demand for our services, or otherwise adversely affect our business;
- interruptions of operations at our facilities due to natural disasters, damage by third parties, power shortages, strikes, riots, terrorism (including cyber-attacks), war or other causes;
- compromise of our IT systems, operational systems or sensitive data as a result of errors, malfunctions, hacking events or coordinated cyber-attacks;
- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves;
- issues, delays or stoppage associated with new construction or expansion projects;

- regulatory, environmental, political, grass roots opposition, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget or at all;

- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;

- the ability of our customers and other counterparties to perform under their contracts with us including as a result of our customers' financial distress or bankruptcy;

- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;

- changes in tax laws;

- our ability to access external sources of financing in sufficient amounts and on acceptable terms to the extent needed to fund acquisitions of operating businesses and assets and expansions of our facilities;

- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;

- our ability to obtain insurance coverage without significant levels of self-retention risk;

- natural disasters, sabotage, terrorism (including cyber-attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;

- possible changes in our and our subsidiaries' credit ratings;

- conditions in the capital and credit markets, inflation and higher interest rates;

- political and economic instability of the oil and natural gas producing nations of the world;

- national, international, regional and local economic, competitive and regulatory conditions and developments, including the effects of any enactment of import or export duties, tariffs or similar measures;

- our ability to achieve cost savings and revenue growth;

- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and work-overs, and in drilling new wells; and

- unfavorable results of litigation and the outcome of contingencies referred to in Note 18 "Litigation and Environmental" to our consolidated financial statements.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results expressed in forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any of our forward-looking statements.

Additional discussion of factors that may affect our forward-looking statements appear elsewhere in this report, including in Item 1A. "*Risk Factors,*" Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and Item 7A. "*Quantitative and Qualitative Disclosures About Market Risk—Energy Commodity Market Risk.*" When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. We disclaim any obligation, other than as required by applicable law, to publicly update or revise any of our forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. *Business and Properties.*

We are one of the largest energy infrastructure companies in North America. We own an interest in or operate approximately 83,000 miles of pipelines, 140 terminals, 700 Bcf of working natural gas storage capacity and have RNG generation capacity of approximately 2.2 Bcf per year of gross production. Our pipelines transport natural gas, renewable fuels, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, renewable fuel feedstocks, chemicals, ethanol, metals and petroleum coke.

General Development of Business

Recent Developments

The following is a listing of significant developments and updates related to our major projects and financing transactions. “Capital Scope” is estimated for our share of the described project which may include portions not yet completed.

Asset or project	Description	Activity	Approx. Capital Scope (KMI Share)
Placed in service, acquisitions or divestitures			
ELC	Sold a 25.5% interest in ELC to an undisclosed financial buyer and now own a 25.5% interest.	Completed in September 2022.	n/a
Mas Ranger	Acquired three landfill assets with the purchase of Mas Ranger, LLC and its subsidiaries from Mas CanAm, LLC. Assets include an RNG facility in Arlington, Texas and Medium British Thermal Units facilities in Shreveport, Louisiana and Victoria, Texas.	Acquired in July 2022.	$358 million
North American Natural Resources	Acquired seven landfill assets with the purchase of North American Natural Resources, Inc. and, its sister companies, North American Biofuels, LLC and North American-Central, LLC (NANR). Assets include GTE facilities in Michigan and Kentucky. A final investment decision was made to convert Autumn Hills, one of the seven landfill assets acquired, to an RNG facility and construction began in January 2023.	Acquired in August 2022.	$132 million
Other Announcements			
Natural Gas Pipelines			
TGP and SNG Evangeline Pass	Two-phase 2 Bcf/d project to serve Venture Global’s proposed Plaquemines LNG facility (Plaquemines). First phase, TGP will provide approximately 0.9 Bcf/d natural gas transportation capacity to Plaquemines. Second phase, TGP and SNG will jointly provide volumes up to the remaining 1.1 Bcf/d to Plaquemines.	Expected in-service date for first phase is fourth quarter of 2024 and third quarter of 2025 for the second phase, pending receipt of all required permits.	$678 million
Eagleford transport project	Expansion project includes constructing 69 miles of 42-inch pipeline, multiple receipt and delivery meters and upgrades to Kinder Morgan Freer compressor station to transport up to 1.88 Bcf/d of lean Eagleford production to Gulf Coast markets.	Expected in-service date is fourth quarter 2023.	$283 million
TGP East 300 Upgrade	Expansion project involves upgrading compression facilities upstream on TGP’s system in order to provide 115,000 Dth/d of capacity to Con Edison’s distribution system in Westchester County, New York. Supported by a long-term contract with Con Edison.	Expected in-service date is November 2023, pending receipt of all required permits.	$263 million
PHP expansion	Joint venture project that will expand PHP’s capacity by approximately 550,000 Dth/d, increasing natural gas deliveries from the Permian to U.S. Gulf Coast markets. Supported by long-term contracts.	Expected in-service date is November 2023.	$149 million

Asset or project	Description	Activity	Approx. Capital Scope (KMI Share)
Greenholly pipeline - North Holly expansion	Joint venture project (our ownership interest of 37.58%) to construct 38 miles of 36-inch pipeline from partner receipt points to KinderHawk wholly owned North Holly gathering system and includes joint venture pipeline receipt interconnects off KinderHawk's Greenwood system, upgrades to KinderHawk's North Holly system and 400 gallons per minute treating capacity addition to KinderHawk's North Holly plant. Supported by long-term contracts.	Expected in-service date is second quarter 2023.	$121 million
3Rivers Offload Phase II	Construct 19 miles of 16-inch pipeline and associated compression allowing delivery of 50,000 Dth/d of incremental gathered production for third-party processing.	Expected in-service date is third quarter 2023.	$96 million
CO_2 - Energy Transition Ventures			
RNG facilities	Construction of three additional landfill-based RNG facilities for Kinetrex in order to provide approximately 3.5 Bcf of RNG a year. Supported by a long-term contract.	Expected to be in service throughout 2023.	$150 million

Financings

During 2022, EPNG issued $300 million and KMI issued $1,500 million of new senior notes to repay maturing debt and for general corporate purposes. On January 17, 2023, we repaid $1,250 million of maturing senior notes using cash on hand and short-term borrowings. On January 31, 2023, we issued $1,500 million of new senior notes to repay short-term borrowings, maturing debt and for general corporate purposes. On January 18, 2023, our board of directors approved an increase in our share repurchase authorization of our share buy-back program from $2 billion to $3 billion. Subsequently, we have approximately $2.1 billion of capacity remaining under this program. During 2022, we repurchased approximately 21.7 million shares of Class P common stock for $368 million at an average price of $16.94 per share.

Narrative Description of Business

Business Strategy

Our business strategy is to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure and energy transition of growing markets within North America or served by U.S. exports;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- exercise discipline in capital allocation and in evaluating expansion projects and acquisition opportunities;
- leverage economies of scale from asset expansions and acquisitions that fit within our strategy; and
- maintain a strong financial profile and enhance and return value to our stockholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A. *"Risk Factors"* below and at the beginning of this report in "*Information Regarding Forward-Looking Statements*," there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

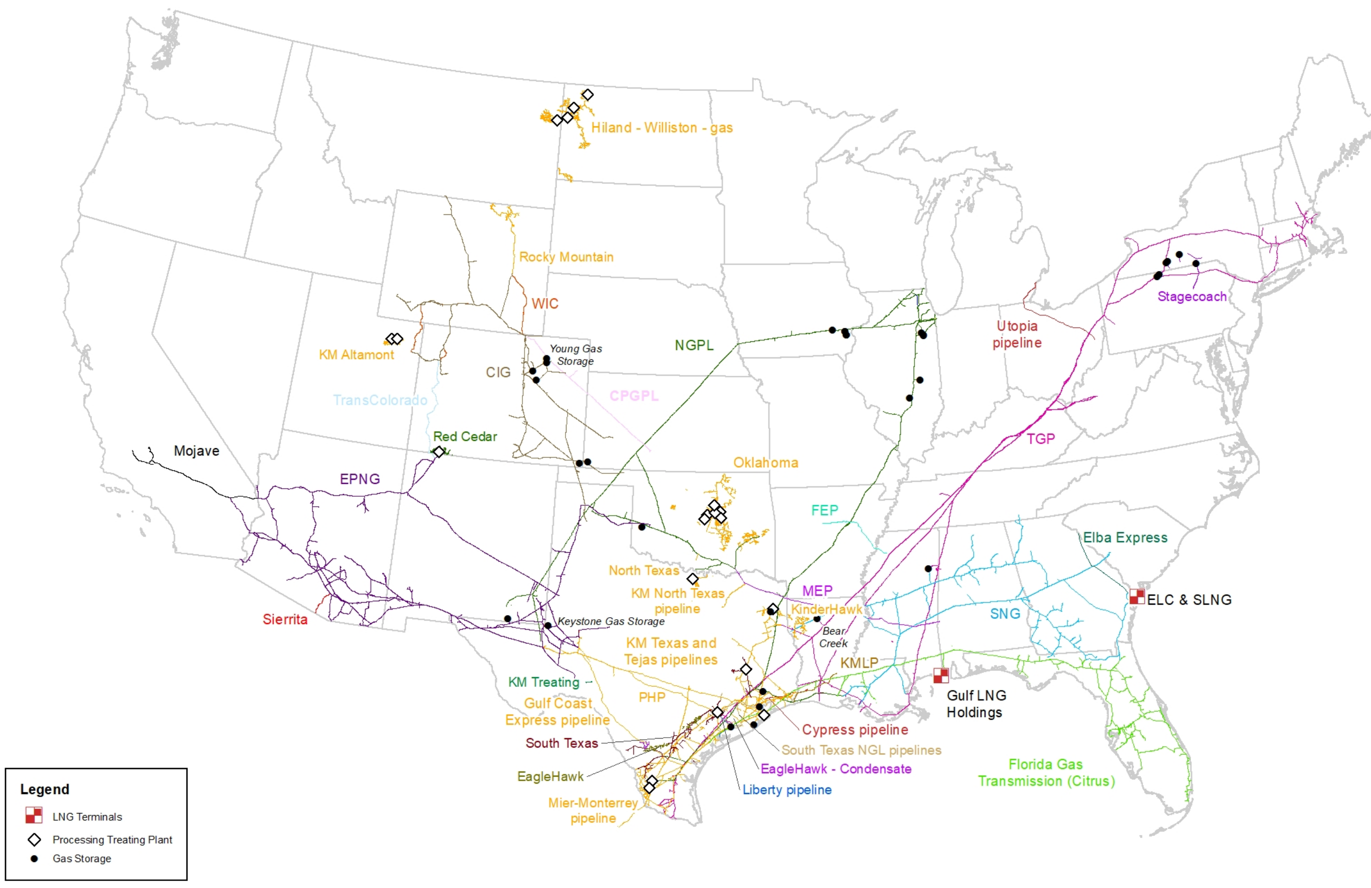
We regularly consider and enter into discussions regarding potential acquisitions and divestitures, and we are currently contemplating potential transactions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, and, as applicable, receipt of fairness opinions, and approval of our board of directors. While there are currently no unannounced purchase or sale agreements for the acquisition or sale of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Business Segments

For financial information on our reportable business segments, see Note 16 "Reportable Segments" to our consolidated financial statements.

Natural Gas Pipelines

Our Natural Gas Pipelines business segment includes interstate and intrastate pipelines, underground storage facilities, our LNG liquefaction and terminal facilities and NGL fractionation facilities, and includes both FERC regulated and non-FERC regulated assets.



Our primary businesses in this segment consist of natural gas transportation, storage, sales, gathering, processing and treating, and various LNG services. Within this segment are: (i) approximately 45,000 miles of wholly owned natural gas pipelines and (ii) our equity interests in entities that have approximately 27,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Rocky Mountain, Midwest, Texas, Louisiana, Southeastern and Northeast regions. Our LNG terminal facilities also serve natural gas market areas in the southeast. The following tables summarize our significant Natural Gas Pipelines business segment assets as of December 31, 2022. The design capacity represents transmission, gathering, regasification or liquefaction capacity, depending on the nature of the asset.

Asset	Ownership Interest	Miles of Pipeline	Design (Bcf/d) [(MBbl/d)] Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity
East Region				
TGP(a)	100 %	11,755	12.23	76
NGPL	37.5 %	9,105	7.84	288
KMLP	100 %	140	3.89	—
Stagecoach	100 %	185	3.22	41
SNG(a)	50 %	6,925	4.47	66

Asset	Ownership Interest	Miles of Pipeline	Design (Bcf/d) [(MBbl/d)] Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity
Florida Gas Transmission (Citrus)	50 %	5,380	4.31	—
MEP	50 %	515	1.81	—
Elba Express	100 %	190	1.10	—
FEP	50 %	185	2.00	—
Gulf LNG Holdings	50 %	5	1.50	7
SLNG	100 %	—	1.76	12
ELC	25.5 %	—	0.35	—
West Region				
EPNG/Mojave	100 %	10,720	6.39	44
CIG(b)	100 %	4,300	6.00	38
WIC	100 %	850	3.61	—
Ruby(c)	50 %	685	1.53	—
CPGPL	100 %	415	1.20	—
TransColorado	100 %	310	0.80	—
Sierrita	35 %	60	0.52	—
Young Gas Storage	47.5 %	15	—	6
Keystone Gas Storage	100 %	15	—	6
Midstream				
KM Texas and Tejas pipelines(d)	100 %	5,915	8.30	136 [0.52]
Mier-Monterrey pipeline(d)	100 %	90	0.65	—
KM North Texas pipeline(d)	100 %	80	0.33	—
Gulf Coast Express pipeline	34 %	530	2.00	—
PHP	26.67 %	435	2.10	—
Oklahoma				
Oklahoma system	100 %	3,225	0.73	[0.09]
Cedar Cove	70 %	120	0.03	—
South Texas				
South Texas system	100 %	1,155	1.93	[1.02]
Webb/Duval gas gathering system	91 %	145	0.15	—
Camino Real	100 %	75	0.15	—
EagleHawk	25 %	550	1.20	—
KM Altamont	100 %	1,535	0.13	[0.1]
Red Cedar	49 %	865	0.33	—
Rocky Mountain				
Fort Union	50 %	315	1.25	—
Bighorn	51 %	265	0.60	—
KinderHawk	100 %	535	2.35	—
North Texas	100 %	530	0.14	—
KM Treating	100 %	—	—	—
Hiland - Williston - gas	100 %	2,190	0.62	[0.33]
Liberty pipeline	50 %	85	[140]	—
South Texas NGL pipelines(e)	100 %	340	[115]	—
Utopia pipeline	50 %	265	[50]	—
Cypress pipeline	50 %	105	[56]	—
EagleHawk - Condensate(f)	25 %	410	[220]	—

(a) Includes proportionate share of storage capacity from our Bear Creek Storage joint venture.

(b) Includes leased pipeline miles and proportionate share of design and storage capacity from our WYCO joint venture.
(c) As of December 31, 2022, we operated Ruby and owned an effective 50% interest. Ruby is not included on the map above. On January 13, 2023, a bankruptcy court confirmed a plan of reorganization satisfactory to all interested parties regarding Ruby which involved the sale of Ruby, and subsequently we no longer hold an interest in Ruby. For further information regarding Ruby's bankruptcy filing, see Note 4 "Gains and Losses on Divestitures, Impairments and Other Write-downs—*Ruby Chapter 11 Bankruptcy Filing*."
(d) Collectively referred to as Texas intrastate natural gas pipeline operations.
(e) Includes proportionate share of design capacity from our Liberty pipeline joint venture.
(f) Asset also has storage capacity of 60 MBbl.

Segment Contracts

Revenues from our interstate natural gas pipelines, related storage facilities and LNG terminals are primarily received under long-term fixed contracts. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed fee reserving the right to transport or store natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize that capacity. Similarly, our Texas Intrastate natural gas pipeline operations currently derive approximately 77% of its sales and transport margins from long-term transport and sales contracts. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2022, the remaining weighted average contract life of our natural gas transportation contracts held by assets we own or have equity interests in (including intrastate pipelines' sales portfolio) was approximately six years. Our LNG regasification and liquefaction and associated storage contracts are subscribed under long-term agreements with a weighted average remaining contract life of approximately 12 years.

Our Midstream assets provide natural gas gathering and processing services. These assets are mostly fee-based, and the revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into its base components, are affected by the volumes of natural gas made available to our systems. Such volumes are impacted by producer rig count and drilling activity. In addition to fee-based arrangements, some of which may include minimum volume commitments, we also provide some services based on percent-of-proceeds, percent-of-index and keep-whole contracts. Our service contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

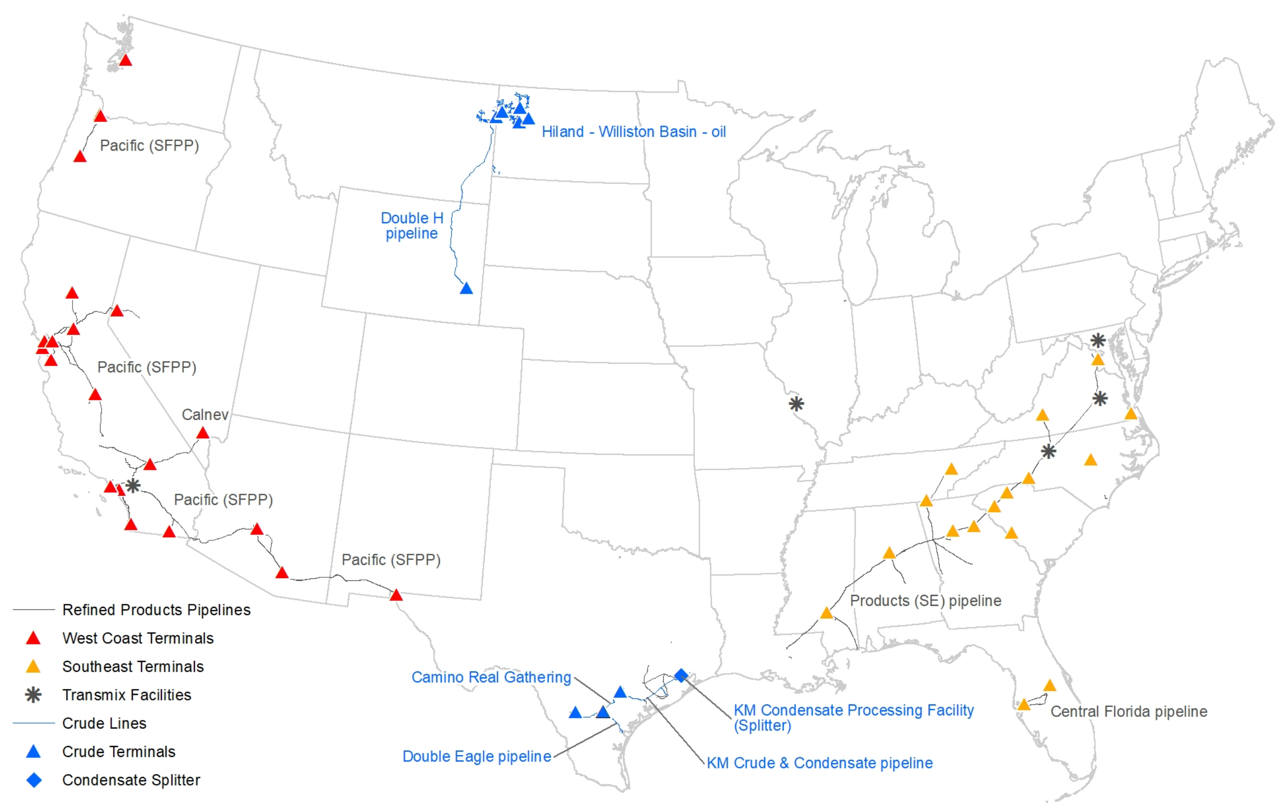
Segment Competition

The market for natural gas infrastructure is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve demand for natural gas in the domestic and export markets served by the pipelines in our Natural Gas Pipelines business segment. We compete with interstate and intrastate pipelines for connections to new markets and supplies and for transportation, processing, storage and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service, flexibility, availability of alternative forms of energy and reliability of service. From time to time, projects are proposed that compete with our existing assets. Whether or when any such projects would be built, or the extent of their impact on our operations or profitability is typically not known.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including oil, coal, nuclear and renewables such as hydro, wind and solar power, along with other evolving forms of renewable energy. Several factors influence the demand for natural gas, including price changes, the availability of supply, other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the ability to convert to alternative fuels and weather.

Products Pipelines

Our Products Pipelines business segment consists of our refined petroleum products, crude oil and condensate pipelines, and associated terminals, our Southeast terminals, our condensate processing facility and our transmix processing facilities.



The following summarizes the significant Products Pipelines business segment assets that we own and operate as of December 31, 2022:

Asset	Ownership Interest	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity (MMBbl)
Crude & Condensate				
KM Crude & Condensate pipeline	100 %	266	5	2.6
Camino Real Gathering	100 %	68	1	0.1
Hiland - Williston Basin - oil(b)	100 %	1,617	7	0.8
Double H pipeline(b)	100 %	512	—	—
Double Eagle pipeline	50 %	204	2	0.6
KM Condensate Processing Facility (Splitter)	100 %	—	1	2.1
Southeast Refined Products				
Products (SE) pipeline	51 %	3,186	—	—
Central Florida pipeline	100 %	206	2	2.6
Southeast Terminals	100 %	—	25	9.3
Transmix Operations	100 %	—	5	0.7
West Coast Refined Products				
Pacific (SFPP)	99.5 %	2,804	13	15.9
Calnev	100 %	566	2	2.1
West Coast Terminals	100 %	44	8	10.1

(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.
(b) Collectively referred to as Bakken Crude assets.

Segment Contracts

The profitability of our refined petroleum products pipeline transportation business generally is driven by the volume of refined petroleum products that we transport and the prices we receive for our services. We also have 49 liquids terminals in this business segment that store fuels and offer blending services for ethanol and biodiesel. The transportation and storage volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and, with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines and terminals located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index and a FERC index rate.

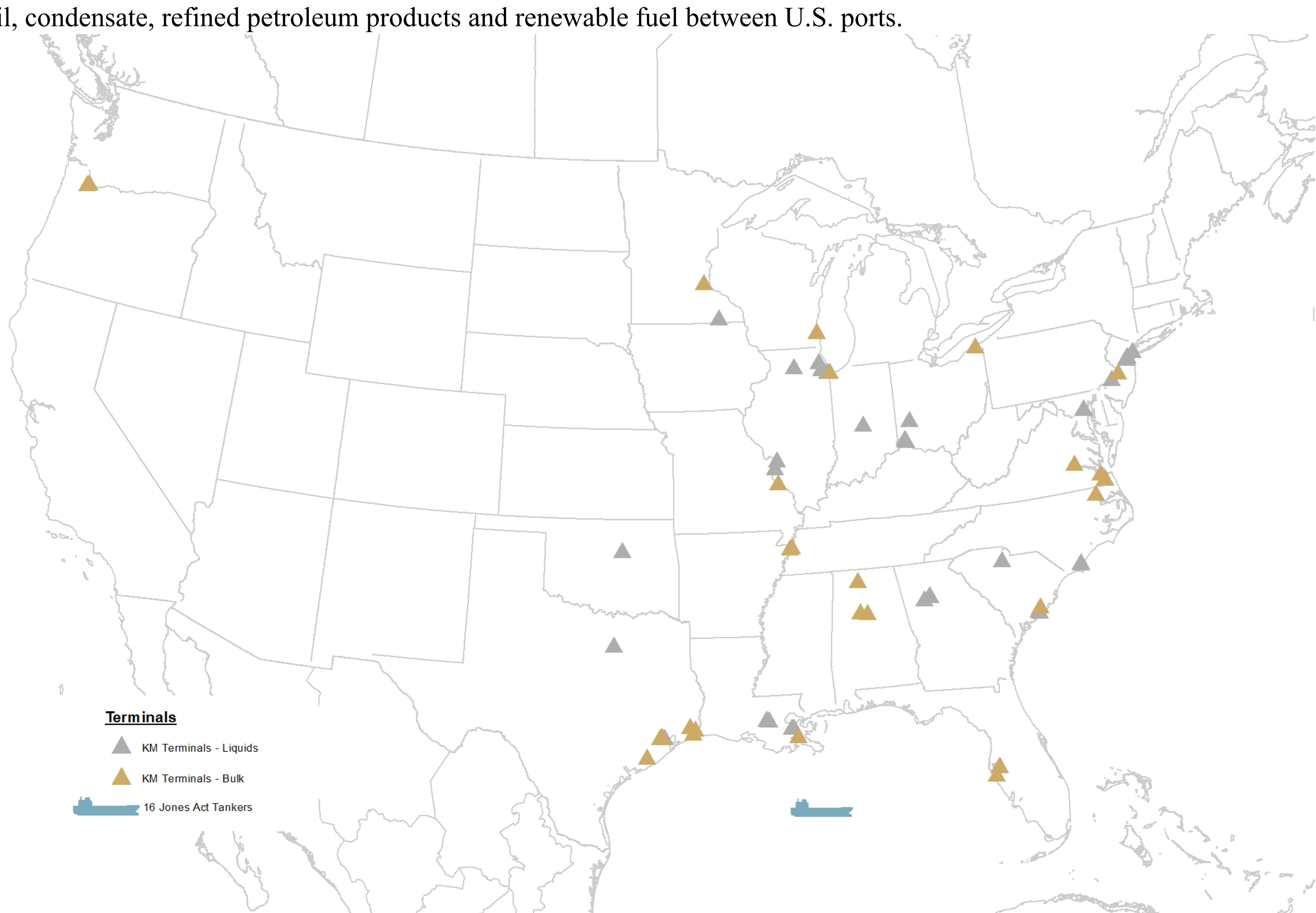
Our crude, condensate and refined petroleum products transportation services are primarily provided pursuant to (i) either FERC or state tariffs (which do not require contractual commitments) or (ii) long-term contracts that normally contain minimum volume commitments. Where we have long-term contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term; however, the revenues and earnings we realize from our pipelines and terminals are affected by the volumes of crude oil, refined petroleum products and condensate available to our pipeline systems, which are impacted by the levels of oil and gas drilling activity and product demand in the respective regions that we serve. Our petroleum condensate processing facility splits condensate into its various components, such as light and heavy naphtha, under a long-term fee-based agreement with a major integrated oil company. Our crude oil marketing activities generate revenues from the sale and delivery of crude oil and condensate purchased either directly from producers or from others on the open market. In general, sales prices referenced in underlying purchase and sales contracts are market-based and include pricing differentials for factors such as delivery location or crude oil quality.

Segment Competition

Our Products Pipelines' pipeline and terminal operations compete against proprietary pipelines and terminals owned and operated by major oil companies, other independent products pipelines and terminals, trucking and marine transportation firms (for short-haul movements of products). Our transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Terminals

Our Terminals business segment includes the operations of our refined petroleum product, chemical, renewable fuel and other liquid terminal facilities (other than those included in the Products Pipelines business segment) and all of our petroleum coke, metal and ores facilities. Our terminals are located primarily near large U.S. urban centers. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide expansion opportunities. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, our Terminals' marine operations include Jones Act-qualified product tankers that provide marine transportation of crude oil, condensate, refined petroleum products and renewable fuel between U.S. ports.



The following summarizes our Terminals business segment assets, as of December 31, 2022:

	Number	Capacity (MMBbl)
Liquids terminals	47	77.8
Bulk terminals	28	—
Jones Act-qualified tankers	16	5.3

Segment Contracts

The factors impacting our Terminals business segment generally differ between liquid and bulk terminals. Our liquids terminals business generally has long-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipelines business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the remaining length of the underlying service contracts (which on a weighted average basis is approximately three years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time.

As with our refined petroleum products pipelines transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are petroleum coke, metals and ores. In addition, the majority of our contracts for this business contain minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize our terminals for all or a specified percentage of their handling and storage needs. The profitability of our minimum volume contracts is generally unaffected by short-term variation in economic conditions; however, to the extent we expect volumes above the minimum and/or have contracts which are volume-based, we can be sensitive to changing market conditions. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related events, including hurricanes, may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

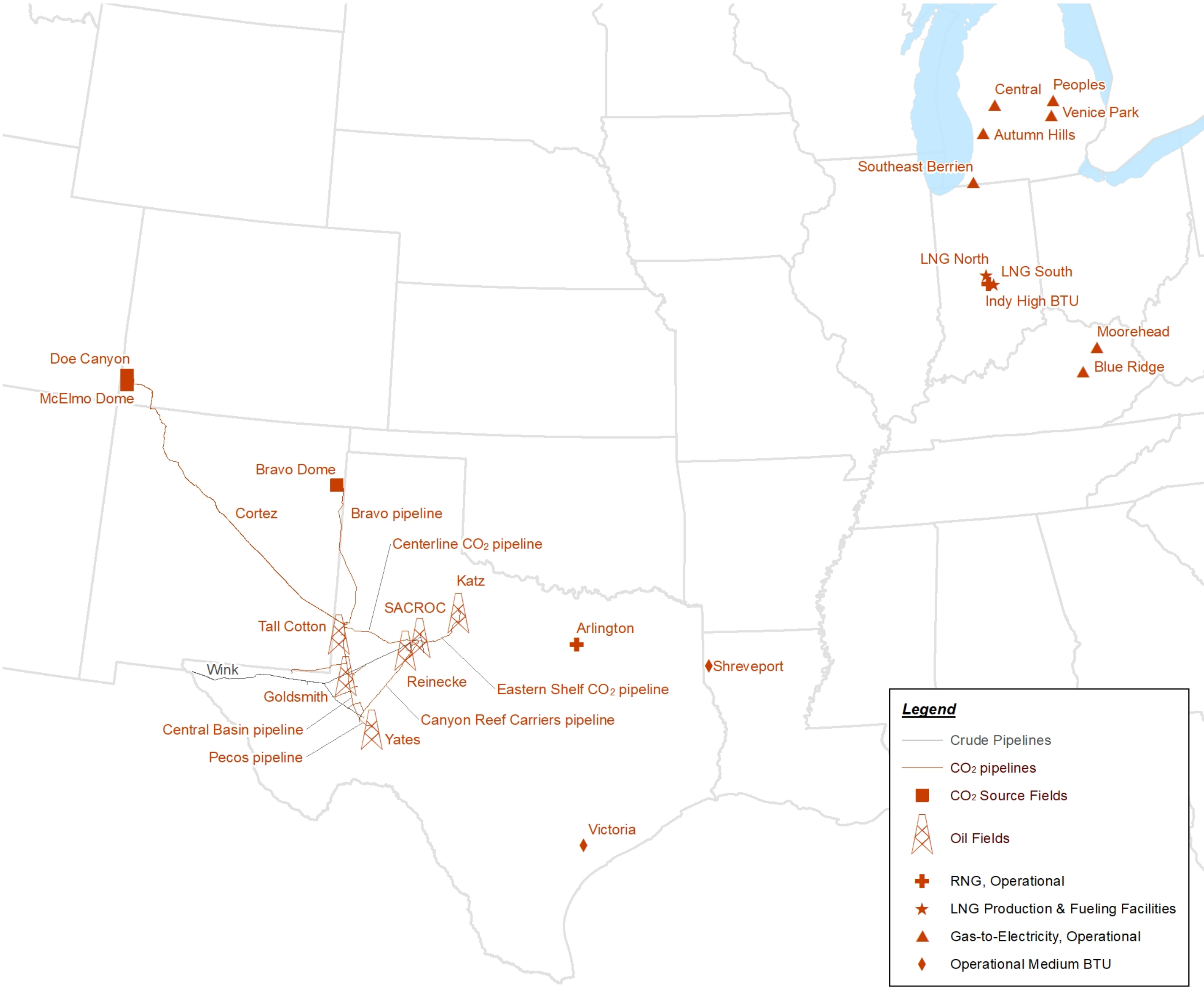
Our Jones Act-qualified tankers provide marine transportation of crude oil, condensate, refined products and renewable fuel in the U.S. and are primarily operating pursuant to fixed price term charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

Segment Competition

We are one of the largest independent operators of liquids terminals in the U.S., based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals and terminals owned by oil, chemical, pipeline and refining companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminaling services. In some locations, competitors are smaller, independent operators with lower cost structures. Our Jones Act-qualified product tankers compete with other Jones Act-qualified vessel fleets.

CO_2

Our CO_2 business segment produces, transports and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. We also own and operate oil and gas producing fields, and RNG, LNG and landfill GTE facilities. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 supply and transportation services to our customers.



Source and Transportation Activities

<u>CO_2 Resource Interests</u>

Our ownership of CO_2 resources as of December 31, 2022 includes:

	Ownership Interest	Compression Capacity (Bcf/d)
McElmo Dome unit	45 %	1.5
Doe Canyon Deep unit	87 %	0.2
Bravo Dome unit(a)	11 %	0.3

(a) We do not operate this unit.

CO$_2$ and Crude Oil Pipelines

Industry demand for transportation on our CO$_2$ pipelines is expected to remain stable for the foreseeable future.

Our ownership of CO$_2$ and crude oil pipelines as of December 31, 2022 includes:

Asset	Ownership Interest	Miles of Pipeline	Transport Capacity (Bcf/d) [(MBbl/d)]
CO$_2$ pipelines			
Cortez pipeline	53 %	569	1.5
Central Basin pipeline	100 %	337	0.7
Bravo pipeline(a)	13 %	218	0.4
Canyon Reef Carriers pipeline	98 %	163	0.3
Centerline CO$_2$ pipeline	100 %	113	0.3
Eastern Shelf CO$_2$ pipeline	100 %	98	0.1
Pecos pipeline	95 %	25	0.1
Crude oil pipeline			
Wink pipeline	100 %	434	[145]

(a) We do not operate Bravo pipeline.

Oil, Gas and RNG Producing Activities

Oil and Gas Producing Interests

Our ownership interests in oil and gas producing fields as of December 31, 2022 include the following:

	Working Interest	KMI Gross Developed Acres
SACROC	97 %	50,316
Yates	50 %	9,576
Goldsmith Landreth San Andres	99 %	6,166
Katz Strawn	99 %	7,194
Reinecke	70 %	3,793
Sharon Ridge(a)	14 %	2,619
Tall Cotton	100 %	641
MidCross(a)	13 %	320

(a) We do not operate these fields.

Our oil and gas producing activities are not significant to KMI as a whole; therefore, we do not include the supplemental information on oil and gas producing activities under Accounting Standards Codification Topic 932, *Extractive Activities – Oil and Gas*.

Gas Plant Interests

Owned and operated gas plants as of December 31, 2022 include:

Asset	Ownership Interest	Source
Snyder gas plant(a)	22 %	The SACROC unit and neighboring CO$_2$ projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51 %	Snyder gas plant
North Snyder gas plant	100 %	Snyder gas plant

(a) This is a working interest; in addition we have a 28% net profits interest.

RNG, LNG and GTE Facilities

Owned and operated RNG, LNG and GTE facilities as of December 31, 2022 include:

Asset	Ownership Interest	Storage [Production] Generation Capacity(a)	Product
LNG Indy	100 %	2 Bcf	LNG
Indy High BTU	50 %	[0.8 Bcf]	RNG
Southeast Berrien	100 %	4.8 mW/h	GTE
Autumn Hills	100 %	4.0 mW/h	GTE
Central	100 %	4.0 mW/h	GTE
Venice Park	100 %	6.4 mW/h	GTE
Peoples	100 %	4.8 mW/h	GTE
Morehead	100 %	1.6 mW/h	GTE
Blue Ridge	100 %	1.6 mW/h	GTE
Arlington RNG	100 %	7.3 mcf/d	RNG
Shreveport RNG(b)	— %	3.8 mcf/d	Medium BTU
Victoria RNG	100 %	1.4 mcf/d	Medium BTU

(a) GTE generation capacity is measured in megawatts per hour (mW/h). RNG and Medium British Thermal Units (BTU) gas capacities are measured in thousands of cubic feet per day (mcf/d).
(b) We operate Shreveport for a fee and receive royalties on RNG sales.

Segment Contracts

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2022 had a remaining average contract life of approximately eight years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our current sales contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. Beginning in 2022, due to the floor price associated with a significant sales contract no longer being a component of the pricing formula, only a small percentage of our sales contracts will be based on a fixed fee or floor price. Our success in this portion of the CO_2 business segment can be impacted by the demand for CO_2. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. The revenues we receive from our crude oil and NGL sales are affected by the prices we realize from the sale of these products. Over the long-term, we tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed or bracketed through the use of financial derivative contracts, particularly for crude oil. See Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Segment Earnings Results*" for more information on crude oil sales prices.

Segment Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. We compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2022, 2021 and 2020, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Industry Regulation

Our business operations are subject to extensive federal, state and local laws and regulations. Please read Item 1A. "*Risk Factors—Risks Related to Regulation*" for discussions of the risks we face related to regulation. For information related to pending regulatory proceedings, see Note 18 "Litigation and Environmental" to our consolidated financial statements.

Interstate Natural Gas Transportation and Storage Regulation

We operate our interstate natural gas pipeline and storage facilities subject to the jurisdiction of the FERC and the provisions of the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 (NGPA), and the Energy Policy Act of 2005 (the Energy Policy Act). These laws give the FERC authority over the construction and operation of such facilities, including their modification, extension, enlargement and abandonment.

Pursuant to the NGA, the FERC also has authority over the rates charged and terms and conditions of services offered by interstate natural gas pipeline and storage companies. The FERC's regulatory authority extends to establishing minimum and maximum rates for services and allows operators to discount or negotiate rates on a non-discriminatory basis. The rates, terms and conditions of service are set forth in posted tariffs approved by the FERC for each of our interstate natural gas pipeline and storage companies. Posted tariff rates are deemed just and reasonable and cannot be changed without FERC authorization following an evidentiary hearing or settlement. The FERC can initiate proceedings, on its own initiative or in response to a shipper complaint, that could result in a rate change or confirm existing rates. Negotiated rates provide certainty to the pipeline and the shipper of agreed-upon rates during the term of the transportation agreement, regardless of changes to the posted tariff rates. Negotiated rate agreements must be filed with the FERC or included in summary form in the pipeline's tariff.

FERC regulations also include a comprehensive framework for market transparency and nondiscrimination, as well as the FERC's prohibition against market manipulation. Under the Energy Policy Act and related regulations, it is unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, to engage in fraudulent conduct. FERC Standards of Conduct regulate, among other things, the manner in which interstate natural gas pipelines may interact with their marketing affiliates. The FERC's market oversight and transparency regulations require annual reports of purchases or sales of natural gas meeting certain thresholds and criteria and certain public postings of information on scheduled volumes.

The FERC has authority to impose civil penalties of more than $1.3 million per day per violation. Should we fail to comply with all applicable statutes, rules, regulations, and orders administered by the FERC, we could be subject to substantial civil penalties and fines.

In addition to having jurisdiction over interstate natural gas pipelines and storage companies, the FERC also has jurisdiction over the interstate transportation and storage services that are provided by intrastate pipelines and storage companies under Section 311 of the NGPA. We have numerous intrastate pipelines and storage companies that provide interstate services pursuant to Section 311 of the NGPA. Under Section 311, along with the FERC's implementing regulations, an intrastate pipeline may transport gas "on behalf of" an interstate pipeline company or any local distribution company served by an interstate pipeline, without becoming subject to the FERC's broader regulatory authority under the NGA. These services must be provided on an open and nondiscriminatory basis, and the rates charged for these services may not exceed a "fair and equitable" level as determined by the FERC in periodic rate proceedings.

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation

Some of our U.S. refined petroleum products and crude oil gathering and transmission pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing gathering or transportation services on our interstate common liquids carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common liquids carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund to shippers the difference between the revenues collected during the pendency of the investigation and the revenues that would have been collected based on the rate the FERC finds to be just and reasonable. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

Petroleum products and crude oil pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. Generally, a petroleum products or crude oil pipeline will utilize the FERC's indexing methodology to adjust its rates, as indexing serves as the default rate-adjustment mechanism. Cost-of-service based rates, market-based rates and settlement rates are alternatives to the default indexing mechanism and may be used in certain specified circumstances to change rates.

CPUC Rate Regulation

The intrastate common carrier operations of our refined products pipelines in California are subject to regulation by the CPUC under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the refined products operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by protest by interested parties or by independent action of the CPUC.

Railroad Commission of Texas (RCT) Rate Regulation

The intrastate operations of our crude oil and liquids pipelines and natural gas pipelines and storage facilities in Texas are subject to regulation with respect to such intrastate transportation by the RCT. The RCT has the authority to regulate our rates, though it generally has not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Mexico - Energy Regulatory Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulatory Commission of Mexico (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2026, subject to an additional 15-year renewal term.

This permit establishes certain restrictive conditions, including without limitation: (i) compliance with the general conditions for the provision of natural gas transportation service; (ii) compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety; (iii) compliance with the technical and economic specifications of the natural gas transportation system authorized by the Commission; (iv) compliance with certain technical studies established by the Commission; and (v) compliance with a minimum contributed capital not entitled to withdrawal of at least the equivalent of 10% of the investment proposed in the project.

Mexico - National Agency for Industrial and Operational Safety and Environmental Protection (ASEA)

ASEA regulates environmental compliance and industrial and operational safety. The Mier-Monterrey Pipeline must satisfy and maintain ASEA's requirements, including compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety, including a Safety Administration Program. The main environmental authorization for the operation of the pipeline is the Environmental Impact Authorization. The Mier-Monterrey Pipeline authorization expires at the end of March 2023, and is currently in the process of being renewed.

Pipeline Safety Regulation

We are also subject to pipeline safety regulations issued by PHMSA as well as any states that are certified by PHMSA to regulate pipeline safety for intrastate pipes in their respective states. These regulations apply to pipelines and pipeline facilities, including associated underground natural gas storage, terminals, and liquefied natural gas facilities. PHMSA regulations in particular, require us to develop and maintain pipeline integrity management programs to evaluate our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas (HCAs) for both gas and liquid pipelines and Moderate Consequence Areas (MCAs) for gas pipelines, where a leak or rupture could potentially do the most harm.

In the past several years, PHMSA has passed several new rules that impose additional pipeline safety requirements including without limitation: (i) expanding certain integrity management program requirements outside of HCAs (with some exceptions) for both gas and hazardous liquid pipelines; (ii) requiring reconfirmation of the maximum allowable operating pressure (MAOP) by 2035 on certain gas pipelines; (iii) installation of remote control or automatic shut-off valves (or alternative equivalent technology) on certain newly constructed or replaced gas pipelines; (iv) increasing requirements for corrosion control; and (v) providing additional prescriptive requirements that increase conservatism and specificity on the evaluation of discovered anomalies and their associated repair criteria.

OSHA

We are also subject to the requirements of federal and state agencies, including, where appropriate, the Occupational Safety and Health Administration (OSHA), that address, among other things, employee health and safety.

State and Local Regulation

Certain of our activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, pipeline safety, protection of the environment, and human health and safety.

Marine Operations

The operation of tankers and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision, which may result in claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and crewed by U.S. citizens. As a result, we monitor the foreign ownership of our common stock and under certain circumstances consistent with our certificate of incorporation, we have the right to redeem shares of our common stock owned by non-U.S. citizens. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. Furthermore, from time to time, legislation has been introduced unsuccessfully in the U.S. Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and crewed by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign-flagged vessels.

In addition, the U.S. Coast Guard and the American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

The Merchant Marine Act of 1936 is a federal law that provides the U.S. Secretary of Transportation, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our vessels were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, we would not be entitled to compensation for any consequential damages suffered as a result of such purchase or requisition.

Derivatives Regulation

We use energy commodity derivative contracts as part of our strategy to hedge our exposure to energy commodity market risk and other external risks in the ordinary course of business. The derivative contracts that we use include exchange-traded and OTC commodity financial instruments such as futures and options contracts, fixed price swaps and basis swaps. The Dodd-Frank Act requires the U.S. Commodity Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. In October 2020, the CFTC finalized one of the last remaining new rules pursuant to the Dodd-Frank Act that institutes broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. As finalized, these rules include exemptions for hedging positions.

Environmental Matters

Our business operations are subject to extensive federal, state and local laws and regulations relating to environmental protection and human health and safety. For example, if a leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up the leak, release or spill, pay government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. Furthermore, new projects may require permits, approvals and environmental analyses under federal and state laws, including the Clean Water Act, the Clean Air Act, the National Environmental Policy Act and the Endangered Species Act, as well as Executive Orders focused on environmental justice considerations. The resulting costs and liabilities could be material to us, and increasing compliance costs under federal and state environmental laws for both new and existing facilities could require us to make significant capital expenditures. In general, the cost of environmental control at facilities is increasing and limiting the return on capital projects and the number of capital projects that are viable. Please read Item 1A. "*Risk Factors—Risks Related to Regulation.*"

In accordance with GAAP, we record liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. For information related to pending environmental matters, including our accruals of environmental reserves, see Note 18 "Litigation and Environmental" to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

We generate both hazardous and non-hazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. RCRA establishes standards for the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes.

Superfund

The CERCLA or the Superfund law, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons for releases of hazardous substances into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, including remediation costs. Additionally, CERCLA allows for the recovery of compensation for natural resource damages, if any. Although petroleum is excluded from CERCLA's definition of a hazardous substance, in the course of our ordinary operations, we have and will generate materials that may fall within the definition of "hazardous substance." By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to evaluate and remediate sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of greenhouse gas (GHG) emissions from stationary sources. For further information, see *"—Climate Change"* below.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of fills and pollutants into waters of the U.S. The discharge of fills and pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal or state authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act pertaining to prevention of and response to oil spills. Spill prevention, control and countermeasure requirements of the Clean Water Act and some state laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release of oil.

EPA Revisions to Ozone National Ambient Air Quality Standard (NAAQS)

As required by the Clean Air Act, the EPA establishes National Ambient Air Quality Standards (NAAQS) for how much pollution is permissible, and the states then have to adopt rules so their air quality meets the NAAQS. In October 2015, the

EPA published a rule lowering the ground level ozone NAAQS from 75 parts per billion (ppb) to a more stringent 70 ppb standard. This change triggered a process under which the EPA designated the areas of the country in or out of compliance with the 2015 standards. In December 2020, EPA completed a review of the ozone NAAQS and published a rule retaining the 2015 standards. State rules implementing the NAAQS, including those existing or proposed in Colorado and New Mexico, require the installation of more stringent air pollution controls on newly-installed equipment and possibly require the retrofitting of existing KMI facilities with air pollution controls. These rules will have financial impacts to our Natural Gas Business Unit. Future state rules could have financial impacts on multiple business units.

Climate Change

Due to concern over climate change, numerous proposals to monitor and limit emissions of GHGs have been made and are likely to continue to be made at the federal, state and local levels of government. Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of burning natural gas, are examples of GHGs. Various laws and regulations exist or are under development to regulate the emission of such GHGs, including the EPA programs to report GHG emissions and state actions to develop statewide or regional programs. The U.S. Congress has in the past considered legislation to reduce emissions of GHGs.

Beginning in 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain GHGs, including CO_2 and methane. Certain of our facilities are subject to these requirements. Operational or physical changes to existing facilities could require those facilities to comply with these requirements. In addition, proposed regulatory changes, if enacted, would require almost all existing oil and natural gas facilities to reduce GHG emissions.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, such as through establishment of GHG reduction targets or regional GHG “cap and trade” programs. It is possible that sources such as our gas-fueled compressors and processing plants could become subject to these state GHG reduction regulations. Various states are also proposing or have implemented stricter regulations for reporting, monitoring or reducing GHGs that go beyond the requirements of the EPA. Compliance with state rules could require additional expenditures, above and beyond those spent to comply with the November 2021 proposed EPA GHG rules for new and existing sources.

Because our operations, including the compressor stations and processing plants, emit various types of GHGs, primarily methane and CO_2, such new legislation or regulation could increase the costs related to operating and maintaining our facilities. Depending on the particular law, regulation or program, we or our subsidiaries could be required to incur capital expenditures for installing new monitoring equipment or emission controls on the facilities, acquire and surrender allowances for the GHG emissions, pay taxes related to the GHG emissions and administer and manage a more comprehensive GHG emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated companies in our industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our or our subsidiaries’ pipelines, recovery of costs is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or other regulatory bodies, and the provisions of any final legislation or other regulations. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Because the combustion of natural gas produces lower GHG emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives to reduce GHGs could stimulate demand for natural gas by increasing the relative cost of competing fuels such as coal and oil. In addition, we anticipate that GHG regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO_2 business segment. However, these potential positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, GHG regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

The Department of Homeland Security, referred to in this report as the DHS, has regulatory authority over security at certain high-risk chemical facilities. The DHS has promulgated the Chemical Facility Anti-Terrorism Standards and required all high-risk chemical and industrial facilities, including oil and gas facilities, to comply with the regulatory requirements of these standards. This process includes completing security vulnerability assessments, developing site security plans, and implementing protective measures necessary to meet DHS-defined, risk-based performance standards. The DHS has not provided final notice to all facilities that it determines to be high risk and subject to the rule; therefore, neither the extent to which our facilities may be subject to coverage by the rules nor the associated costs to comply can currently be determined, but it is possible that such costs could be substantial.

Cybersecurity

In response to ongoing cybersecurity threats affecting the pipeline industry, the DHS's Transportation Safety Administration, or TSA, has issued a series of security directives setting forth specific elements that all pipeline owners and operators must include in their cybersecurity planning and their reporting of any incidents. These security directives require, among other things, that pipeline owners comply with mandatory reporting measures; designate a cybersecurity coordinator; provide vulnerability assessments; ensure compliance with certain cybersecurity requirements; establish and implement a TSA-approved Cybersecurity Implementation Plan; develop and maintain a Cybersecurity Incident Response Plan; and establish a Cybersecurity Assessment Program, and submit an annual plan that describes how owners will assess the effectiveness of cybersecurity measures.

In addition, PHMSA requires reporting of any event that involves a release from or the shutdown of a pipeline, including because of a cyber-attack. The SEC has issued guidance outlining its position on cybersecurity disclosure requirements that apply under federal securities laws, but new binding rules imposing affirmative reporting requirements were proposed in March 2022 and are expected to be finalized in 2023. Also under development is the Cyber Incident Reporting for Critical Infrastructure Act of 2022 (CIRCIA), a law concerning the reporting of cyber incidents and ransomware payments that was signed into law in early 2022 and is expected to take effect in early 2024.

Human Capital

In managing our human capital resources, we use a strategic approach to building a diverse, inclusive, and respectful workplace. Our human resources department provides expertise and tools to attract, develop, and retain diverse talent and support our employees' career and development goals. Our leadership teams have plans in place to enhance diversity and equality of opportunity in hiring, development, and promotions. We value our employees' opinions and encourage them to engage with management and ask questions on topics such as our goals, challenges and employee concerns.

We employed 10,525 full-time personnel at December 31, 2022, including approximately 888 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2023 and 2027. We consider relations with our employees to be good.

We value the safety of our workforce and integrate a culture of safety, emergency preparedness and environmental responsibility through our operations management system (OMS). Our OMS conforms to common industry standards and establishes a framework that helps us (i) provide employees and contractors with a safe work environment; (ii) comply with laws, rules, regulations, policies, and procedures; and (iii) identify opportunities to improve. Although our ultimate target is zero incidents, we also have three non-zero employee safety performance targets as follows:

Non-zero employee safety performance target	**2022 Company-wide TRIR** (excluding COVID-19 cases)
Outperform the annual industry average total recordable incident rate (TRIR)	
Outperform our own three-year TRIR average	**1.9** (0.8)
Improve our company-wide employee TRIR from 1.0 in the baseline year 2019 to 0.7 by 2024	

We seek to constantly improve our contractor TRIR performance through initiatives to address recent incident trends and new best practices.

Our board of directors' nominating and governance committee is responsible for planning for succession in the senior management ranks of the Company, including the office of chief executive officer. The chief executive officer shall report to the committee, generally at the time of the regularly scheduled third quarter board of directors meeting in each year, regarding the processes in place to identify talent within and outside the Company to succeed to senior management positions and the information developed during the current calendar year pursuant to those processes. As part of our annual succession planning process, we identify minority and female candidates to include in the plan for senior positions. Management reviews its succession plan, including a discussion on development opportunities for potential successors, with the nominating and governance committee of our board of directors annually.

We consider employee diversity an asset and support equal opportunity employment. We take affirmative steps to employ and advance in employment all persons without regard to their race/ethnicity; sex; sexual orientation; gender, including gender identity and expression; veteran status; disability; or other protected categories, and base employment decisions solely on valid job requirements. We are committed to a harassment free workplace, supported with online and face-to-face workplace harassment and discrimination prevention training for our employees. Employees and supervisors review our harassment and discrimination prevention policy every two years as part of our policy renewal training.

Our employees are an integral part of our success, and we value their career development. We encourage and support professional development and learning for our employees by offering workforce training, tuition reimbursement, leadership and other development programs. These programs help improve recruitment, development, and retention. We support our employees' ongoing career goals and development through several programs. These programs help maximize our employees' potential and give them the skills they need to further enhance their careers.

Our compensation program is linked to long- and short-term strategic financial and operational objectives, including environmental, safety, and compliance targets. Compensation includes competitive base salaries in the markets in which we operate and competitive benefits, including retirement plans, opportunities for annual bonuses, and, for eligible employees, long-term incentives and an employee stock purchase plan.

Properties and Rights-of-Way

We believe we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state or local government land.

We generally do not own the land on which our pipelines are constructed. Instead, we obtain and maintain rights to construct and operate the pipelines on other people's land generally under agreements that are perpetual or provide for renewal rights. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of a majority of the interests have been obtained. Permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits also have been obtained from railroad companies to run along or cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased by the Company.

Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 16 "Reportable Segments" to our consolidated financial statements.

Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. ***Risk Factors.***

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Risks Related to Operating our Business

Our businesses are dependent on the supply of and demand for the products we handle.

Our pipelines, terminals and other assets and facilities, including the availability of expansion opportunities, depend in part on continued production of natural gas, crude oil and other products in the geographic areas that they serve. Without additions to crude oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers in areas served by us may not be successful in exploring for and developing additional reserves or their costs of doing so may become uneconomic. Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire. Our business also depends in part on the levels of demand for natural gas, crude oil, NGL, refined petroleum products, CO_2, steel, chemicals and other products in the geographic areas to which our pipelines, terminals, shipping vessels and other facilities deliver or provide service, and the ability and willingness of our shippers and other customers to supply such demand. Decreases in the supply of or demand for natural gas, crude oil and other products could adversely impact the utilization of our assets.

Economic disruptions, such as those which occurred during the COVID-19 pandemic, or conditions in the business environment generally, such as declining or sustained low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our pipelines, terminals and other assets. Also, sustained lower demand for hydrocarbons, or changes in the regulatory environment or applicable governmental policies, including in relation to climate change or other environmental concerns, may have a negative impact on the supply of crude oil and other products. In recent years, a number of initiatives and regulatory changes relating to reducing GHG emissions have been undertaken by federal, state and municipal governments and crude oil and gas industry participants. In addition, public concern about the potential risks posed by climate change has resulted in increased demand for energy efficiency and a transition to energy provided from renewable energy sources rather than fossil fuels, fuel-efficient alternatives such as hybrid and electric vehicles, and pursuit of other technologies to reduce GHG emissions, such as carbon capture and sequestration. We have seen and may see further intensification of these trends if and to the extent that the Biden presidential administration succeeds in further enacting its energy and environmental policies.

Each of the foregoing could negatively impact our business directly, as well as our shippers and other customers, which in turn could negatively impact our prospects for new contracts for transportation, terminaling or other midstream services, or renewals of existing contracts or the ability of our customers and shippers to honor their contractual commitments. Furthermore, such unfavorable conditions may compound the adverse effects of larger disruptions such as COVID-19. See "*—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.*" below.

We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for the products we handle.

We face competition from other pipelines and terminals, as well as other forms of transportation and storage.

Competition is a factor affecting our existing businesses and our ability to secure new project opportunities. Any current or future pipeline system or other form of transportation (such as barge, rail or truck) that delivers the products we handle into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. Likewise, competing terminals or other storage options may become more attractive to our customers. To the extent that competitors offer the markets we serve more desirable transportation or storage options, or customers opt to construct their own facilities for services previously provided by us, this could result in unused capacity on our pipelines and in our terminals. We also could experience competition for the supply of the products we handle from both existing and proposed pipeline systems; for example, several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us. If capacity on our assets remains unused, our ability to re-contract for expiring capacity at favorable rates or otherwise retain existing customers could be impaired. In addition, to the extent that companies pursuing development of carbon capture and sequestration technology are successful, they could compete with us for customers who purchase CO_2 for use in enhanced oil recovery operations.

The volatility of crude oil, NGL and natural gas prices could adversely affect our business.

The revenues, cash flows, profitability and future growth of some of our businesses (and the carrying values of certain of their respective assets, which include related goodwill) depend to a large degree on prevailing crude oil, NGL and natural gas prices.

Prices for crude oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for crude oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) domestic and global economic conditions; (iii) the activities of the OPEC and other countries that are significant producers of crude oil (OPEC+); (iv) governmental regulation; (v) armed conflict or political instability in crude oil and natural gas producing countries; (vi) the foreign supply of and demand for crude oil and natural gas; (vii) the price of foreign imports; (viii) the proximity and availability of storage and transportation infrastructure and processing and treating facilities; and (ix) the availability and prices of alternative fuel sources. We use hedging arrangements to partially mitigate our exposure to commodity prices, but these arrangements also are subject to inherent risks. Please read "*—Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.*" In addition, wide fluctuations in commodity prices can impact the accuracy of assumptions used in our budgeting process.

If commodity prices fall substantially or remain low for a sustained period and we are not sufficiently protected through hedging arrangements, we may be unable to realize a profit from these businesses and would operate at a loss.

Sharp declines in the prices of crude oil, NGL or natural gas, or a prolonged unfavorable price environment, may result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell crude oil, NGL, or natural gas, and could have a material adverse effect on the carrying value (which includes assigned goodwill) of our CO_2 business segment's proved reserves, certain assets in certain midstream businesses within our Natural Gas Pipelines business segment, and certain assets within our Products Pipelines business segment. For example, following the commodity price declines we experienced due to COVID-19 during the first half of 2020, we recorded a combined $1.950 billion of non-cash impairments associated with our Natural Gas Pipelines Non-Regulated and CO_2 reporting units, primarily for impairments of goodwill and assets owned in these businesses. See Note 4 "Gains and Losses on Divestitures, Impairments and Other Write-downs" and Note 8 "Goodwill" to our consolidated financial statements for more information.

For more information about our energy and commodity market risk, see Item 7A. "*Quantitative and Qualitative Disclosures About Market Risk*."

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to the transportation and storage of the products we handle, such as leaks; releases; the breakdown, underperformance or failure of equipment, facilities, information systems or processes; damage to our pipelines caused by third-party construction; the compromise of information and control systems; spills at terminals and hubs; spills associated with loading and unloading harmful substances at rail facilities; adverse sea conditions (including storms and rising sea levels) and releases or spills from our shipping vessels or vessels loaded at our marine terminals; operator error; labor disputes/work stoppages; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries on which our assets depend; and catastrophic events or natural disasters such as fires, floods, explosions, earthquakes, acts of terrorists and saboteurs, cyber security breaches, and other similar events, many of which are beyond our control. Additional risks to our vessels include capsizing, grounding and navigation errors.

The occurrence of any of these risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution, significant reputational damage, impairment or suspension of operations, fines or other regulatory penalties, costs associated with responding to an investigation or enforcement action brought by a governmental agency, and revocation of regulatory approvals or imposition of new requirements, any of which also could result in substantial financial losses, including lost revenue and cash flow to the extent that an incident causes an interruption of service. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. In addition, the consequences of any operational incident (including as a result of adverse sea conditions) at one of our marine terminals may be even more significant as a result of the complexities involved in addressing leaks and releases occurring in the ocean or along coastlines and/or the repair of marine terminals.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Unfavorable conditions such as a general slowdown of the global or U.S. economy, uncertainty and volatility in the financial markets, or inflation and rising interest rates, could materially adversely affect our operating results. For example, COVID-19 resulted in a global economic downturn in 2020. The slowdown resulting from the pandemic affected numerous industries, including the crude oil and gas industry, the steel industry and specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. While global economic activity largely rebounded in 2021, we could experience similar or compounded adverse impacts as a result of other global events affecting economic conditions. Also, economic conditions in the wake of the pandemic have included inflationary pressure, which has resulted in higher operating expenses and project costs for us, as well as higher interest rates.

In addition, uncertain or changing economic conditions within one or more geographic regions may affect our operating results within the affected regions. Sustained unfavorable commodity prices, volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which could impair their ability to meet their obligations to us. See *"—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us."* In addition, decreases in the prices of crude oil, NGL and natural gas are likely to have a negative impact on our operating results and cash flow. See *"—The volatility of crude oil, NGL and natural gas prices could adversely affect our business."*

If economic and market conditions (including volatility in commodity markets) globally, in the U.S. or in other key markets become more volatile or deteriorate, we may experience material impacts on our business, financial condition and results of operations.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of nonperformance by our customers or other counterparties, such as hedging counterparties, joint venture partners and suppliers. Many of our counterparties finance their activities through cash flow from operations or debt or equity financing, and some of them may be highly leveraged and may not be able to access additional capital to sustain their operations in the future. Our counterparties are subject to their own operating, market, financial and regulatory risks, and some have experienced, are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. Further, the security we are able to obtain from such customers may be limited, including by FERC regulation. While certain of our customers are subsidiaries of an entity that has an investment grade credit rating, in many cases the parent entity has not guaranteed the obligations of the subsidiary and, therefore, the parent's credit ratings may have no bearing on such customers' ability to pay us for the services we provide or otherwise fulfill their obligations to us. See Note 2 "Summary of Significant Accounting Policies—*Allowance for Credit Losses*" in our consolidated financial statements.

Furthermore, financially distressed customers might be forced to reduce or curtail their future use of our products and services, which also could have a material adverse effect on our results of operations, financial condition, and cash flows.

We cannot provide any assurance that such customers and key counterparties will not become financially distressed or that such financially distressed customers or counterparties will not default on their obligations to us or file for bankruptcy protection. If one or more customers or counterparties files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion of, amounts they owe to us. Similarly, our contracts with such customers may be renegotiated at lower rates or terminated altogether. Significant customer and other counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows.

We are subject to reputational risks and risks relating to public opinion.

Our business, operations or financial condition generally may be negatively impacted as a result of negative public opinion towards our industry sector, the products we handle, or us specifically. Public opinion may be influenced by negative portrayals of the industry in which we operate as well as opposition to development projects. In addition, market events specific to us could result in the deterioration of our reputation with key stakeholders.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. In particular, our reputation could be impacted by negative publicity related to pipeline incidents or unpopular expansion projects and due to opposition to development of hydrocarbons and energy infrastructure, particularly projects involving resources that are considered to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include increased regulatory oversight, difficulty obtaining rights-of-way and delays in obtaining, or challenges to, regulatory approvals with respect to growth projects, blockades, project cancellations, difficulty securing financing, revenue loss, reduction in customer base, and decreased value of our securities and our business. Moreover, governmental agencies have responded to environmental justice concerns by imposing greater scrutiny in permitting approvals and enforcement actions that could exacerbate such negative impacts.

Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.

We engage in hedging arrangements to reduce our direct exposure to fluctuations in the prices of crude oil, natural gas and NGL, including differentials between regional markets. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for crude oil, natural gas and NGL. Furthermore, our hedging arrangements cannot hedge against any decrease in the volumes of products we handle. See "*—Our businesses are dependent on the supply of and demand for the products we handle.*"

The markets for instruments we use to hedge our commodity price exposure generally reflect then-prevailing conditions in the underlying commodity markets. As our existing hedges expire, we will seek to replace them. To the extent then-existing underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions, limiting our ability to hedge our exposure to unfavorable commodity prices.

When we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those consolidated financial statements. In addition, it may not be possible for us to engage in hedging transactions that completely eliminate our exposure to commodity prices; therefore, our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge. For more information about our hedging activities, see Item 7A. "*Quantitative and Qualitative Disclosures About Market Risk*" and Note 14 "Risk Management" to our consolidated financial statements.

A breach of information security or the failure of one or more key information technology (IT) or operational (OT) systems, or those of third parties, may adversely affect our business, results of operations or business reputation.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. Some of the operational systems we use are owned or operated by independent third-party vendors. The various uses of these systems, networks and services include, but are not limited to, controlling our pipelines and terminals with industrial control systems, collecting and storing information and data, processing transactions, and handling other processes necessary to manage our business.

In accordance with government mandates, we have implemented and maintain a cybersecurity program—both internal and incorporating industry expertise—designed to protect our IT, OT and data systems from attacks, however, we can provide no assurance that our cybersecurity program will be completely effective. We have experienced increases in the number of attempts by external parties to access our networks or our company data without authorization. While we have taken additional steps to secure our networks and systems to specifically respond to new and elevated risks associated with recent increases in remote work, we may nevertheless be more vulnerable to a successful cyber-attack or information security incident when significant numbers of our employees are working remotely. The risk of a disruption or breach of our operational systems, or the compromise of the data processed in connection with our operations, has increased as attempted attacks, including acts of terrorism or cyber sabotage, have advanced in sophistication and number around the world.

If any of our systems are damaged, fail to function properly or otherwise become unavailable, we may incur substantial costs to repair or replace them. We may also experience loss or corruption of critical data and interruptions or delays in our ability to perform critical functions, which could adversely affect our business and results of operations. A significant failure, compromise, breach or interruption in our systems, which may result from problems such as ransomware, malware, computer viruses, hacking attempts or third-party error or malfeasance, could result in a disruption of our operations, customer dissatisfaction, damage to our reputation and a loss of customers or revenues. Efforts by us and our vendors to develop, implement and maintain security measures, including malware and anti-virus software and controls, may not be successful in preventing these events, and any network and information systems-related events could require us to expend significant remedial resources. In the future, we may be required to expend significant additional resources to continue to enhance our information security measures, to comply with regulations, to develop and implement government-mandated plans, and/or to investigate and remediate information security vulnerabilities.

Attacks, including acts of terrorism or cyber sabotage, or the threat of such attacks, may adversely affect our business or reputation.

The U.S. government has issued public warnings indicating that pipelines and other infrastructure assets might be specific targets of terrorist organizations or “cyber sabotage” events. For example, in May 2021, a ransomware attack on a major U.S. refined products pipeline forced the operator to temporarily shut down the pipeline, resulting in disruption of fuel supplies along the East Coast. Potential targets include our pipeline systems, terminals, processing plants, databases or operating systems. The occurrence of an attack could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, significant reporting requirements, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. In the event of such an incident, we may need to retain cybersecurity experts to assist us in stopping, diagnosing, and recovering from the attack. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. The potential for an attack may subject our operations to increased risks and costs, and, depending on their ultimate magnitude, have a material adverse effect on our business, results of operations, financial condition and/or business reputation.

Hurricanes, earthquakes, flooding and other natural disasters, as well as subsidence and coastal erosion and climate-related physical risks, could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines, terminals and other assets are located in, and our shipping vessels operate in, areas that are susceptible to hurricanes, earthquakes, flooding and other natural disasters or could be impacted by subsidence and coastal erosion. These natural disasters could potentially damage or destroy our assets and disrupt the supply of the products we transport. Many climate models indicate that global warming is likely to result in rising sea levels, increased frequency and severity of weather events such as winter storms, hurricanes and tropical storms, extreme precipitation and flooding. These climate-related changes could result in damage to our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. Natural disasters can similarly affect the facilities of our customers. The timing, severity and location of these climate change impacts are not known with certainty, and these impacts are expected to manifest themselves over varying time horizons.

In addition, we may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially. See “*—Risks Related to Regulation—Climate-related risks and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.*”

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our insurance program may not cover all operational risks and costs and may not provide sufficient coverage in the event of a claim. We do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

Changes in the insurance markets subsequent to certain hurricanes and other natural disasters have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by one or more of our insurers to honor its coverage commitments for an insured event, could have a material adverse effect on our business, financial condition and results of operations. Insurance companies may reduce the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. There is no assurance that our insurers will renew their insurance coverage on acceptable terms, if at all, or that we will be able to arrange for adequate alternative coverage in the event of non-renewal. The unavailability of full insurance coverage to cover events in which we suffer significant losses could have a material adverse effect on our business, financial condition and results of operations.

Expanding our existing assets and constructing new assets is part of our growth strategy. Our ability to begin and complete expansion and new-build projects may be inhibited by difficulties in obtaining permits and rights-of-way, public opposition, increases in costs of construction materials, cost overruns, inclement weather and other delays. Should we pursue projects through joint ventures with others, we will share control of and any benefits from those projects.

We regularly undertake construction projects to expand our existing assets and to construct new assets. New growth projects generally will be subject to, among other things, the receipt of regulatory approvals, feasibility and cost analyses, funding availability and industry, market and demand conditions, and environmental justice considerations. A variety of factors outside of our control, such as difficulties in obtaining rights-of-way and permits or other regulatory approvals, have caused, and may continue to cause, delays in or cancellations of our construction projects. Regulatory authorities may modify their permitting policies in ways that disadvantage our construction projects, such as the FERC's ongoing evaluation of its process for reviewing and approving applications for construction of natural gas infrastructure, including consideration of changes to its Certificate Policy Statement and its issuance of a Draft GHG Policy Statement. Federal regulators may also expand existing regulatory requirements, such as PHMSA's recent expansion of gas gathering pipeline regulation and PHMSA's consideration of regulating the transportation of gaseous CO_2. Such factors can be exacerbated by public opposition to our projects. See "*—We are subject to reputational risks and risks relating to public opinion.*" Inclement weather, natural disasters and delays in performance by third-party contractors have also resulted in, and may continue to result in, increased costs or delays in construction. In addition, we may experience increasing costs for construction materials. Significant increases in costs of construction materials, cost overruns or delays, or our inability to obtain a required permit or right-of-way, could have a material adverse effect on our return on investment, results of operations and cash flows, and could result in project cancellations or limit our ability to pursue other growth opportunities.

If we pursue joint ventures with third parties, those parties may share approval rights over major decisions, and may act in their own interests. Their views may differ from our own or our views of the interests of the venture which could result in operational delays or impasses, which in turn could affect the financial expectations of and our expected benefits from the venture.

Substantially all of the land on which our pipelines are located is owned by third parties. If we are unable to procure and maintain access to land owned by third parties, our revenue and operating costs, and our ability to complete construction projects, could be adversely affected.

We must obtain and maintain the rights to construct and operate pipelines on other owners' land, including private landowners, railroads, public utilities and others. While our interstate natural gas pipelines in the U.S. have federal eminent domain authority, the availability of eminent domain authority for our other pipelines varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas, CO_2, or crude oil—and the laws of the particular state. In any case, we must compensate landowners for the use of their property, and in eminent domain actions, such compensation may be determined by a court. If we are unable to obtain rights-of-way on acceptable terms, our ability to complete construction projects on time, on budget, or at all, could be adversely affected. In addition, we are subject to the possibility of increased costs under our rights-of-way or rental agreements with landowners, primarily through renewals of expiring agreements and rental increases. If we were to lose these rights, our operations could be disrupted or we could be required to relocate the affected pipelines, which could cause a substantial decrease in our revenues and cash flows and a substantial increase in our costs.

The acquisition of additional businesses and assets is part of our growth strategy. We may experience difficulties completing acquisitions or integrating new businesses and properties, and we may be unable to achieve the benefits we expect from any future acquisitions.

Part of our business strategy includes acquiring additional businesses and assets. We cannot provide any assurance that we will be able to find complementary acquisition targets or complete such acquisitions, or achieve the desired results from any acquisitions we do complete. Any acquired businesses or assets will be subject to many of the same risks as our existing businesses and may not achieve the levels of performance that we anticipate.

We may not realize anticipated operating advantages and cost savings. Integration of acquired businesses or assets involves a number of risks, including (i) the loss of key customers of the acquired business; (ii) demands on management related to the increase in our size; (iii) the diversion of management's attention from the management of daily operations; (iv) difficulties in implementing or unanticipated costs of accounting, budgeting, reporting, internal controls and other systems; and (v) difficulties in the retention and assimilation of necessary employees.

Difficulties in integration may be magnified if we make multiple acquisitions over a relatively short period of time. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable, which involves risks that may result in a total loss of investment.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves, revenues and cash flows of the oil and gas producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

Developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational and market-related factors may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable.

Our business requires the retention and recruitment of a skilled executive team and workforce, and difficulties recruiting and retaining executives and other key personnel could impair our ability to develop and implement our business strategy.

Our success depends in part on the performance of and our ability to attract, retain and effectively manage the succession of a skilled executive team. We depend on our executive officers to develop and execute our business strategy. If we are not successful in retaining our executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

In addition, our business requires the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete the knowledge transfer; and/or (iii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Risks Related to Financing Our Business

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of December 31, 2022, we had approximately $31.7 billion of consolidated debt (excluding debt fair value adjustments). Additionally, we and substantially all of our wholly owned U.S. subsidiaries are parties to a cross guarantee agreement under which each party to the agreement unconditionally guarantees the indebtedness of each other party, which means that we are liable for the debt of each of such subsidiaries. This level of consolidated debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth, or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our consolidated debt, and our ability to meet our consolidated leverage targets, will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our consolidated cash flow is not sufficient to service our consolidated debt, and any future indebtedness that we incur, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may also take such actions to reduce our indebtedness if we determine that our earnings (or consolidated EBITDA, as calculated in accordance with our revolving credit facility) may not be sufficient to meet our consolidated leverage targets or to comply with consolidated leverage ratios required under certain of our debt agreements. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 9 “Debt” to our consolidated financial statements.

Our business, financial condition and operating results may be affected adversely by adverse changes in the availability, terms and cost of capital or a reduction in the availability of credit.

We may need to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund acquisitions, capital projects or refinancing debt maturities. Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings (which would have a corresponding impact on the credit ratings of our subsidiaries that are party to the cross guarantee agreement) could cause our cost of doing business to increase by limiting our access to capital, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn reduce our cash flows, and could limit our ability to pursue acquisition or expansion opportunities. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries’ debt securities and the terms available to us for future issuances of debt securities.

Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, impacting our ability to finance our operations and strategy on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

Our and our customers’ access to capital could be affected by evolving financial institutions’ policies concerning businesses linked to fossil fuels.

Our and our customers’ access to capital could be affected by financial institutions’ evolving policies concerning businesses linked to fossil fuels. Concerns about the potential effects of climate change have caused some to direct their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in such companies. Ultimately, this could make it more difficult for our customers to secure funding for exploration and production activities or for us to secure funding for growth projects, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2022, approximately $6.3 billion of our approximately $31.7 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps. Variable-to-fixed interest rate swap agreements covering an additional $1.25 billion of our consolidated debt will expire at the end of 2023. In response to increasing inflation, the U.S. Federal Reserve raised interest rates in March 2022 for the first time in over three years, raised rates several more times since and has signaled it expects to make additional rate increases. As interest rates increase, the amount of cash required to service variable-rate debt also increases, as do our costs to refinance maturities of existing indebtedness, and our earnings and cash flows could be adversely affected.

For more information about our interest rate risk, see Item 7A. “*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*”

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that may be beneficial to us. Some of the agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more limiting restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Risks Related to Regulation

The FERC or state public utility commissions, such as the CPUC, may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, state public utility commissions or our customers could initiate proceedings or file complaints challenging the tariff rates charged by our pipelines, which could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what we are permitted by the FERC or state public utility commissions to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact on our operating results.

Our existing rates may also be challenged by complaint or protest. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators seeking prospective reductions in the tariff rates and, in the case of a protest to a rate filing, seeking substantial refunds for alleged overcharges during the years in question. Further, the FERC has initiated and may continue to initiate investigations to determine whether our interstate natural gas pipeline rates are just and reasonable. Please read Note 18 "Litigation and Environmental" to our consolidated financial statements for a description of material pending challenges to the rates we charge on our pipelines. We are unable to predict the extent to which these proceedings will result in lower transportation rates on our pipelines, and in the case of a protest, refunds for alleged overcharges. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

New laws, policies, regulations, rulemaking and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to extensive regulation and oversight by federal, state and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these authorities, have the potential to adversely affect our profitability. Additional regulatory burdens and uncertainties will be created if and to the extent that more stringent energy and environmental and pipeline safety policies are enacted. Overall, we have seen an increase in the efforts of regulatory authorities to issue new regulations and guidance and to interpret existing laws and regulations in ways that promote the use of renewable energy sources and further protection of the environment, call upon companies to increase monitoring and emissions reduction efforts, and increase investigations and enforcement actions for potential violations of environmental laws. For example, in November 2021, the EPA proposed a rule containing standards of performance for GHG emissions, in the form of methane limitations, and volatile organic compound emissions for crude oil and natural gas sources, including the production, processing, transmission and storage segments. In November 2022, the EPA announced a supplemental proposal expanding on the November 2021 proposed rule aimed at achieving more comprehensive emissions reductions from oil and natural gas sources. In April 2022, the EPA proposed a rule calling for significant reductions in nitrogen oxide emissions in 26 states, including on new and existing natural gas fired reciprocating engines used at compressor stations. These types of proposals, if finalized, would affect our assets and operations indirectly, such as by increasing the costs associated with the production of natural gas and liquids that we transport, or directly, such as by increasing significantly our capital and operating costs associated with impacted equipment.

These and other initiatives of regulatory authorities may affect our assets and operations directly or indirectly, such as by preventing or delaying the exploration for and production of natural gas and liquids that we transport or expanding regulation of existing infrastructure or new sources that are not currently regulated.

Regulation affects almost every part of our business. In addition to environmental and pipeline safety matters, we are subject to regulations extending to such matters as (i) federal, state and local taxation; (ii) rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the integrity, safety and security (including against cyber-attacks) of facilities and operations; (vii) the acquisition of other businesses; (viii) the acquisition, extension, disposition or abandonment of services or facilities; (ix) reporting and information posting requirements; (x) the maintenance of accounts and records; and (xi) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of such regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes, applicable to our income, operations, assets or another aspect of our business could have a material adverse impact on our earnings, cash flow, financial condition and results of operations. For more information, see Items 1 and 2. "*Business and Properties—Narrative Description of Business—Industry Regulation.*"

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to extensive federal, state and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our past, present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. It is possible that costs associated with complying with the aforementioned laws will increase as a result of the emphasis regulatory authorities are placing on protection of the environment and environmental justice considerations. Liability under such laws and regulations may be incurred without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act, the Oil Pollution Act, or analogous state laws, as a result of the presence or release of hydrocarbons and other hazardous substances into or through the environment, and these laws may require response actions and remediation and may impose liability for natural resource and other damages. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations, including required permits and other approvals, also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could harm our business, financial position, results of operations and prospects. For example, if a leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, shipping vessels or storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures.

We own and/or operate numerous properties and equipment that have been used for many years in connection with our business activities and contain hydrocarbons or other hazardous substances. While we believe we have utilized operating, handling and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties and equipment owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and any hazardous substances released and wastes disposed at or from them may be subject to U.S. laws such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws, we could be required to remove previously disposed wastes, remediate property contamination or both, including contamination caused by prior owners or operators. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our pipeline or liquids or bulk terminal operations or wastes from oil and gas facilities that are currently exempt as being exploration and production waste, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Environmental and health and safety laws and regulations are subject to change. The long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health, including without limitation, the exploration, development, storage and transportation of oil and gas. For example, the Federal Clean Air Act and other similar federal and state laws are subject to periodic review and amendment, which could result in more stringent emission control requirements obligating us to make significant capital expenditures at our facilities. Several state and federal agencies have also increased their daily and maximum penalty amounts in recent years. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate.

New or revised regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, as well as increased penalty amounts for inadvertent non-compliance, such as a pipeline leak, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Items 1 and 2. "*Business and Properties—Narrative Description of Business—Environmental Matters*."

Increased regulatory requirements relating to the safety and integrity of our pipelines may require us to incur significant capital and operating expense outlays to comply.

We are subject to extensive laws and regulations related to pipeline safety and integrity at the federal and state levels. There are, for example, regulations issued by PHMSA for pipeline operators in the areas of design, operations, integrity testing, repairs, qualification and training, emergency response, control room management, and public awareness. We expect the costs of compliance with these regulations, including integrity management rules, will be substantial. The majority of compliance costs relate to pipeline integrity testing and repairs and reconfirmation of the maximum allowable operating pressure on our gas pipelines. Technological advances in in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in HCAs or MCAs can have a significant impact on integrity testing and repair costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA rules. Repairs or upgrades deemed necessary to address results of integrity assessments and other testing and/or ensure the continued safe and reliable operation of our pipelines and pipeline facilities could cause us to incur significant and unanticipated capital and operating expenditures. Such expenditures will vary depending on the number of repairs determined to be necessary as a result of integrity assessments and other testing. We expect to increase expenditures in the future to comply with PHMSA regulations.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. Pipeline safety regulations or changes to such regulations may require additional leak detection, reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent monitoring, inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures. Pipeline safety regulation has increased over time, including recent final gas and hazardous liquid regulations that we must timely implement, and existing obligations may increase with new proposed rules that are currently under consideration. Congress is set to reauthorize the Pipeline Safety Act in 2023, which could further expand PHMSA's current rulemaking agenda and/or statutory authority in certain areas. For example, PHMSA is working on a number of proposed rulemakings projected for publication in 2023, including those related to (i) pipeline leak detection and repair; (ii) updating regulations for LNG facilities; (iii) inspection and maintenance requirements for idled pipelines; and (iv) revising existing requirements for transportation of CO_2 in the liquid phase as well as establishing regulation of the transportation of gaseous CO_2 (projected in 2024). There can be no assurance as to the amount or timing of future expenditures for pipeline safety and integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate-related risks and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of GHGs such as methane and CO_2, including the EPA programs to control GHG emissions, PHMSA's existing and anticipated leak detection and repair requirements, and state actions to develop statewide or regional programs. Existing EPA regulations require us to report GHG emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO_2 (for example, from our McElmo Dome CO_2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further address GHG emissions include establishing GHG "cap and trade" programs, a fee on methane emissions from petroleum and natural gas systems, increased efficiency standards, participation in international climate agreements, issuance of executive orders by the U.S. presidential administration and incentives or mandates for pollution reduction, use of renewable energy sources, or use of alternative fuels with lower carbon content. For more information about climate change regulation, see Items 1 and 2. "*Business and Properties—Narrative Description of Business—Environmental Matters—Climate Change.*"

Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities, expand existing facilities or construct new facilities. We could be required to install new emission controls on our facilities, acquire allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Such laws or regulations could also lead to reduced demand for hydrocarbon products that are deemed to contribute to GHGs, or restrictions on their use, which in turn could adversely affect demand for our products and services. See also "*—Business Risks—We are subject to reputational risks and risks relating to public opinion.*" and "*—Business Risks—Hurricanes, earthquakes, flooding and other natural disasters, as well as subsidence and coastal erosion and climate-related physical risks, could have an adverse effect on our business, financial condition and results of operations*."

In March 2022, the SEC proposed new climate-related disclosure rules, which if adopted as proposed, would require significant new climate-related disclosure in SEC filings, including certain climate-related metrics and GHG emissions data, and third-party attestation requirements. At this time, we cannot predict the costs of compliance with or any potential adverse impacts resulting from, the new rules if adopted as proposed.

Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including activity on public lands, could result in reductions or delays in drilling and completing new oil and natural gas wells, as well as reductions in production from existing wells, which could adversely impact the volumes of natural gas transported on our natural gas pipelines and our own oil and gas development and production activities.

We gather, process or transport crude oil, natural gas or NGL from several areas, including lands that are federally managed. Policy and regulatory initiatives or legislation by Congress may decrease access to federally managed lands or increase the regulatory burdens associated with using these lands to produce crude oil or natural gas, or both. Recently, the federal government has deprioritized onshore leasing and its review of applications for permits to drill. Third-party interests groups and members of the oil and gas industry have initiated litigation challenging decisions to approve or prohibit oil and gas activities on federally managed lands.

In addition, oil and gas development and production activities are subject to increasing regulation at the federal, state and local levels. For example, there have been initiatives at the federal and state levels to regulate or otherwise restrict the use of certain hydraulic fracturing activities, and many states are promulgating stricter requirements related not only to well development but also to compressor stations and other facilities in the oil and gas industry. These activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities and location, emissions into the environment, water discharges, transportation of hazardous materials, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities.

Adoption of legislation or regulations restricting these activities in our areas of operations could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of crude oil, natural gas or NGL and, in turn, adversely affect our revenues, cash flows and results of operations by decreasing the volumes of these commodities that we handle. These laws and regulations may also adversely affect our own oil and gas development and production activities.

The Jones Act includes restrictions on ownership by non-U.S. citizens of our U.S. point to point maritime shipping vessels, and failure to comply with the Jones Act, or changes to or a repeal of the Jones Act, could limit our ability to operate our vessels in the U.S. coastwise trade, result in the forfeiture of our vessels or otherwise adversely impact our earnings, cash flows and operations.

We are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and crewed by predominately U.S. citizens. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Proposed changes to U.S. federal, state, and local tax laws, if enacted, could have a material adverse effect on our business and profitability.

New federal, state, or local tax legislation or administrative guidance may be enacted or issued in the future, and such legislation or guidance could materially impact our current or future tax planning and effective tax rates. It is unclear (i) whether these or similar changes will occur, (ii) if such changes occur, when such changes will become effective, and (iii) whether such changes will have a material adverse effect on our business, profitability, financial position, results of operations, or cash flows.

Risks Related to Ownership of Our Capital Stock

The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.

We disclose in this report and elsewhere the expected cash dividends on our common stock. These reflect our current judgment, but as with any estimate, they may be affected by inaccurate assumptions and other risks and uncertainties, many of which are beyond our control. See "*Information Regarding Forward-Looking Statements*" at the beginning of this report. If our board of directors elects to pay dividends at the anticipated level and that action would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, to maintain our leverage metrics or otherwise to properly address our business prospects, our business could be harmed.

Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated levels. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, may decide to address those matters by reducing our anticipated dividends. Alternatively, because nothing in our governing documents or credit agreements prohibits us from borrowing to pay dividends, we could choose to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed above under "*—Risks Related to Financing Our Business—Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions*."

Our certificate of incorporation restricts the ownership of our common stock by non-U.S. citizens within the meaning of the Jones Act. These restrictions may affect the liquidity of our common stock and may result in non-U.S. citizens being required to sell their shares at a loss.

The Jones Act requires, among other things, that at least 75% of our common stock be owned at all times by U.S. citizens, as defined under the Jones Act, in order for us to own and operate vessels in the U.S. coastwise trade. As a safeguard to help us maintain our status as a U.S. citizen, our certificate of incorporation provides that, if the number of shares of our common stock owned by non-U.S. citizens exceeds 22%, we have the ability to redeem shares owned by non-U.S. citizens to reduce the percentage of shares owned by non-U.S. citizens to 22%. These redemption provisions may adversely impact the marketability of our common stock, particularly in markets outside of the U.S. Further, those stockholders would not have control over the timing of such redemption and may be subject to redemption at a time when the market price or timing of the redemption is disadvantageous. In addition, the redemption provisions might have the effect of impeding or discouraging a merger, tender offer or proxy contest by a non-U.S. citizen, even if it were favorable to the interests of some or all of our stockholders.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

See Note 18 "Litigation and Environmental" to our consolidated financial statements.

Item 4. ***Mine Safety Disclosures.***

Except for one terminal facility that is in temporary idle status with the Mine Safety and Health Administration, we do not own or operate mines for which reporting requirements apply under the mine safety disclosure requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank). We have not received any specified health and safety violations, orders or citations, related assessments or legal actions, mining-related fatalities, or similar events requiring disclosure pursuant to the mine safety disclosure requirements of Dodd-Frank for the year ended December 31, 2022.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

As of February 7, 2023, we had 9,941 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

For information on our equity compensation plans, see Note 10 "Share-based Compensation and Employee Benefits—*Share-based Compensation*" to our consolidated financial statements.

Our Purchases of Our Class P Stock
(During the quarter ended December 31, 2022)

Settlement Period	Total number of securities purchased(a)	Average price paid per security(b)	Total number of securities purchased as part of publicly announced plans(a)	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs(a)
October 1 to October 31, 2022	2,056,189	$ 16.75	2,056,189	$ 1,057,284,126
November 1 to November 30, 2022	—	—	—	1,057,284,126
December 1 to December 31, 2022	—	—	—	1,057,284,126
Total	2,056,189	$ 16.75	2,056,189	$ 1,057,284,126

(a) On July 19, 2017, our board of directors approved a $2 billion common share buy-back program. On January 18, 2023, our board of directors approved an increase in our share repurchase authorization to $3 billion from $2 billion, increasing the maximum dollar value of securities that may yet be purchased under the plan as of January 18, 2023 to $2.1 billion. After repurchase, the shares are canceled and no longer outstanding.

(b) Amount includes any commission or other costs to repurchase shares.

Item 6. ***[Reserved]***

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2. "*Business and Properties—Narrative Description of Business—Business Strategy;*" (ii) a description of developments during 2022, found in Items 1 and 2. "*Business and Properties—General Development of Business—Recent Developments;*" (iii) a description of terms for services and commodities we provide, found in Items 1 and 2. *"Business and Properties—Narrative Description of Business—Business Segments;"* (iv) a description of risk factors affecting us and our business, found in Item 1A. "*Risk Factors;*" and (v) a discussion of forward-looking statements, found in "*Information Regarding Forward-Looking Statements*" at the beginning of this report.

A comparative discussion of our 2021 to 2020 operating results can be found in Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations*" included in our Annual Report on Form 10-K for the year ended December 31, 2021 filed with the SEC on February 7, 2022.

General

Significant Acquisitions and Dispositions

Following are significant acquisitions and dispositions during the reporting periods. See Note 3, "Acquisitions and Divestitures" to our consolidated financial statements for further information on these transactions.

Event	Description	Business Segment
Sale of interest in ELC *(September 2022)*	We sold a 25.5% interest in our joint venture ELC. We now own a 25.5% interest in ELC and continue to operate, have a controlling financial interest in and consolidate ELC.	Natural Gas Pipelines business segment *(East Region)*
North American Natural Resources acquisition *(August 2022)*	We acquired seven landfill assets with the purchase of North American Natural Resources, Inc. and, its sister companies, North American Biofuels, LLC and North American-Central, LLC (NANR) consisting of GTE facilities in Michigan and Kentucky.	CO_2 business segment *(Energy Transition Ventures group)*
Mas Ranger acquisition *(July 2022)*	We acquired three landfill assets with the purchase of Mas Ranger, LLC and its subsidiaries from Mas CanAm, LLC, comprising an RNG facility in Arlington, Texas and medium Btu facilities in Shreveport, Louisiana and Victoria, Texas.	CO_2 business segment *(Energy Transition Ventures group)*

February 2021 Winter Storm

Our earnings for 2021 reflect impacts of the February 2021 winter storm that affected Texas, which are largely nonrecurring. See "—Segment Earnings Results" below.

2023 Dividends and Discretionary Capital

We expect to declare dividends of $1.13 per share for 2023, a 2% increase from the 2022 declared dividends of $1.11 per share. We also expect to invest $2.1 billion in expansion projects and contributions to joint ventures, or discretionary capital expenditures during 2023.

The expectations for 2023 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and because of these uncertainties, it is advisable not to put undue reliance on any forward-looking statement. Please read our Item 1A. "*Risk Factors*" and "*Information Regarding Forward-Looking Statements*" at the beginning of this report for more information. Furthermore, we plan to provide updates to these 2022 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

Critical Accounting Estimates

Critical accounting estimates and assumptions involve material levels of subjectivity and complex judgement to account for highly uncertain matters or matters with a high susceptibility to change, and could result in a material impact to our financial statements. Examples of certain areas that require more judgment relative to others when preparing our consolidated financial statements and related disclosures include our use of estimates in determining (i) revenue recognition; (ii) income taxes; (iii) the economic useful lives of our assets and related depletion rates; (iv) the fair values used in (a) assignment of the purchase price for a business acquisition, (b) calculations of possible asset and equity investment impairment charges, (c) calculation for the annual goodwill impairment test (or interim tests if triggered), and (d) recording derivative contract assets and liabilities; (v) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (vi) provisions for credit losses; and (vii) exposures under contractual indemnifications. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

For a summary of our significant accounting policies, see Note 2 “Summary of Significant Accounting Policies” to our consolidated financial statements and the following discussion for further information regarding critical estimates and assumptions used in the preparation of our financial statements. For discussion on our hedging activities and related sensitivities to our estimates, see Note 14 *“*Risk Management*”* to our consolidated financial statements and Item 7A. *“Quantitative and Qualitative Disclosures About Market Risk,”* respectively.

Impairments

In addition to our annual testing of impairment for goodwill, we evaluate impairment of our long-lived assets when a triggering event occurs. Management applies judgment in determining whether there is an impairment indicator. Fair value calculated for the purpose of testing our long-lived assets, including intangible assets, goodwill and equity method investments, for impairment involves the use of significant estimates and assumptions regarding the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The estimates and assumptions can be affected by a variety of factors, including external factors such as industry and economic trends, and internal factors such as changes in our business strategy and our internal forecasts. An estimate of the sensitivity to changes in underlying assumptions of a fair value calculation is not practicable, given the numerous assumptions that can materially affect our estimates.

For more information on our impairments and significant estimates and assumptions used in our impairment evaluations, see Note 4 “Gains and Losses on Divestitures, Impairments and Other Write-downs.”

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. Our accrual of environmental liabilities often coincides either with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our probable environmental liabilities, if necessary or appropriate, following quarterly reviews of potential environmental issues and claims that could impact our assets or operations. In recording and adjusting environmental liabilities, we consider the effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. For more information on environmental matters, see Part I, Items 1 and 2. “*Business and Properties—Narrative Description of Business—Environmental Matters.*” For more information on our environmental disclosures, see Note 18 “Litigation and Environmental” to our consolidated financial statements.

Legal and Regulatory Matters

Many of our operations are regulated by various U.S. regulatory bodies, and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on regulatory matters, see Part I, Items 1 and 2. “*Business and Properties—Narrative Description of Business—Industry Regulation.*” For more information on legal proceedings, see Note 18 “Litigation and Environmental” to our consolidated financial statements.

Employee Benefit Plans

Our pension and OPEB obligations and net benefit costs are primarily based on actuarial calculations. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. The selection of assumptions used in the actuarial calculations of our pension and OPEB plans is further discussed in Note 10 *“*Share-based Compensation and Employee Benefits” to our consolidated financial statements.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and OPEB can be, and have been revised in subsequent periods. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income over either the period of expected future service of active participants, or over the expected future lives of inactive plan participants.

The following sensitivity analysis shows the estimated impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and OPEB plans for the year ended December 31, 2022:

	Pension Benefits		OPEB	
	Net benefit cost (income)	Change in funded status(a)	Net benefit cost (income)	Change in funded status(a)
	(In millions)			
One percent increase in:				
Discount rates	$ (13)	$ 145	$ —	$ 13
Expected return on plan assets	(22)	—	(4)	—
Rate of compensation increase	3	(9)	—	—
One percent decrease in:				
Discount rates	15	(169)	—	(15)
Expected return on plan assets	22	—	4	—
Rate of compensation increase	(3)	8	—	—

(a) Includes amounts deferred as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations.

Income Taxes

We make significant judgments and estimates in determining our provision for income taxes, including our assessment of our income tax positions given the uncertainties involved in the interpretation and application of complex tax laws and regulations in various taxing jurisdictions. Numerous and complex judgments and assumptions are inherent in the estimation of future taxable income when determining a valuation allowance, including factors such as future operating conditions and the apportionment of income by state. For more information, see Note 5 "Income Taxes" to our consolidated financial statements.

Results of Operations

Overview

As described in further detail below, our management evaluates our performance primarily using the GAAP financial measures of Segment EBDA (as presented in Note 16, "Reportable Segments") and Net income attributable to Kinder Morgan, Inc., along with the non-GAAP financial measures of Adjusted Earnings and DCF, both in the aggregate and per share for each, Adjusted Segment EBDA, Adjusted EBITDA and Net Debt.

GAAP Financial Measures

The Consolidated Earnings Results for the years ended December 31, 2022 and 2021 present Segment EBDA and Net income attributable to Kinder Morgan, Inc., which are prepared and presented in accordance with GAAP. Segment EBDA is a useful measure of our operating performance because it measures the operating results of our segments before DD&A and certain expenses that are generally not controllable by our business segment operating managers, such as general and administrative expenses and corporate charges, interest expense, net, and income taxes. Our general and administrative expenses and corporate charges include such items as unallocated employee benefits, insurance, rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services.

Non-GAAP Financial Measures

Our non-GAAP financial measures described below should not be considered alternatives to GAAP Net income attributable to Kinder Morgan, Inc. or other GAAP measures and have important limitations as analytical tools. Our computations of these non-GAAP financial measures may differ from similarly titled measures used by others. You should not consider these non-GAAP financial measures in isolation or as substitutes for an analysis of our results as reported under GAAP. Management compensates for the limitations of these non-GAAP financial measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes.

Certain Items

Certain Items, as adjustments used to calculate our non-GAAP financial measures, are items that are required by GAAP to be reflected in Net income attributable to Kinder Morgan, Inc., but typically either (i) do not have a cash impact (for example, unsettled commodity hedges and asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses). We also include adjustments related to joint ventures (see "Amounts from Joint Ventures" below and the tables included in *"—Consolidated Earnings Results (GAAP)—Certain Items Affecting Consolidated Earnings Results," "—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted EBITDA" and "—Non-GAAP Financial Measures—Supplemental Information"* below). In addition, Certain Items are described in more detail in the footnotes to tables included in *"—Segment Earnings Results"* and *"—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests"* below.

Adjusted Earnings

Adjusted Earnings is calculated by adjusting Net income attributable to Kinder Morgan, Inc. for Certain Items. Adjusted Earnings is used by us and certain external users of our financial statements to assess the earnings of our business excluding Certain Items as another reflection of our ability to generate earnings. We believe the GAAP measure most directly comparable to Adjusted Earnings is Net income attributable to Kinder Morgan, Inc. Adjusted Earnings per share uses Adjusted Earnings and applies the same two-class method used in arriving at basic earnings per share. See *"—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF"* below.

DCF

DCF is calculated by adjusting Net income attributable to Kinder Morgan, Inc. for Certain Items (Adjusted Earnings), and further by DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. We also include amounts from joint ventures for income taxes, DD&A and sustaining capital expenditures (see "Amounts from Joint Ventures" below). DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as dividends, stock repurchases, retirement of debt, or expansion capital expenditures. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is Net income attributable to Kinder Morgan, Inc. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends. See *"—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF"* and *"—Non-GAAP Financial Measures—Adjusted Segment EBDA to Adjusted EBITDA to DCF"* below.

Adjusted Segment EBDA

Adjusted Segment EBDA is calculated by adjusting Segment EBDA for Certain Items attributable to the segment. Adjusted Segment EBDA is used by management in its analysis of segment performance and management of our business. We believe Adjusted Segment EBDA is a useful performance metric because it provides management and external users of our financial statements additional insight into the ability of our segments to generate cash earnings on an ongoing basis. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA. See *"—Consolidated Earnings Results (GAAP)—Certain Items Affecting Consolidated Earnings Results"* for a reconciliation of Segment EBDA to Adjusted Segment EBDA by business segment.

Adjusted EBITDA

Adjusted EBITDA is calculated by adjusting EBITDA for Certain Items. We also include amounts from joint ventures for income taxes and DD&A (see "Amounts from Joint Ventures" below). Adjusted EBITDA is used by management and external users, in conjunction with our Net Debt (as described further below), to evaluate our leverage. Therefore, we believe Adjusted EBITDA is useful to investors. We believe the GAAP measure most directly comparable to Adjusted EBITDA is Net income attributable to Kinder Morgan, Inc. See *"—Adjusted Segment EBDA to Adjusted EBITDA to DCF"* and *"—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted EBITDA"* below.

Amounts from Joint Ventures

Certain Items, DCF and Adjusted EBITDA reflect amounts from unconsolidated joint ventures and consolidated joint ventures utilizing the same recognition and measurement methods used to record “Earnings from equity investments” and “Noncontrolling interests,” respectively. The calculations of DCF and Adjusted EBITDA related to our unconsolidated and consolidated joint ventures include the same items (DD&A and income tax expense, and for DCF only, also cash taxes and sustaining capital expenditures) with respect to the joint ventures as those included in the calculations of DCF and Adjusted EBITDA for our wholly-owned consolidated subsidiaries. (See *“—Non-GAAP Financial Measures—Supplemental Information”* below.) Although these amounts related to our unconsolidated joint ventures are included in the calculations of DCF and Adjusted EBITDA, such inclusion should not be understood to imply that we have control over the operations and resulting revenues, expenses or cash flows of such unconsolidated joint ventures.

Net Debt

Net Debt is calculated, based on amounts as of December 31, 2022, by subtracting the following amounts from our total debt balance of $31,788 million: (i) cash and cash equivalents of $745 million; and (ii) debt fair value adjustments of $115 million; and excluding the foreign exchange impact on Euro-denominated bonds of $(8) million for which we have entered into currency swaps to convert that debt to U.S. dollars. Net Debt is a non-GAAP financial measure that management believes is useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debt is total debt.

Consolidated Earnings Results (GAAP)

The following tables summarize the key components of our consolidated earnings results.

	Year Ended December 31,			
	2022	2021	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$ 4,801	$ 3,815	$ 986	26 %
Products Pipelines	1,107	1,064	43	4 %
Terminals	975	908	67	7 %
CO_2	819	760	59	8 %
Total segment EBDA	7,702	6,547	1,155	18 %
DD&A	(2,186)	(2,135)	(51)	(2)%
Amortization of excess cost of equity investments	(75)	(78)	3	4 %
General and administrative and corporate charges	(593)	(623)	30	5 %
Interest, net	(1,513)	(1,492)	(21)	(1)%
Income before income taxes	3,335	2,219	1,116	50 %
Income tax expense	(710)	(369)	(341)	(92)%
Net income	2,625	1,850	775	42 %
Net income attributable to noncontrolling interests	(77)	(66)	(11)	(17)%
Net income attributable to Kinder Morgan, Inc.	$ 2,548	$ 1,784	$ 764	43 %

(a) Includes revenues, earnings from equity investments, operating expenses, (gain) loss on divestitures and impairments, net, other income, net and other, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

Year Ended December 31, 2022 vs. 2021

Net income attributable to Kinder Morgan, Inc. increased $764 million in 2022 compared to 2021. The increase was primarily due to the $1,600 million non-cash impairment loss and associated income tax benefit in 2021 related to South Texas gathering and processing assets within our Natural Gas Pipeline segment and higher earnings across all of our business segments partially offset by the benefit in the 2021 period of $1,092 million for largely nonrecurring pre-tax earnings related to the February 2021 winter storm, mostly impacting the earnings from our Natural Gas Pipelines and CO_2 business segments.

Certain Items Affecting Consolidated Earnings Results

	Year Ended December 31,						
	2022			2021			
	GAAP	Certain Items	Adjusted	GAAP	Certain Items	Adjusted	Adjusted amounts increase/(decrease) to earnings
				(In millions)			
Segment EBDA							
Natural Gas Pipelines	$ 4,801	$ 141	$ 4,942	$ 3,815	$ 1,648	$ 5,463	$ (521)
Products Pipelines	1,107	—	1,107	1,064	53	1,117	(10)
Terminals	975	—	975	908	42	950	25
CO_2	819	(11)	808	760	(6)	754	54
Total Segment EBDA(a)	7,702	130	7,832	6,547	1,737	8,284	(452)
DD&A and amortization of excess cost of equity investments	(2,261)	—	(2,261)	(2,213)	—	(2,213)	(48)
General and administrative and corporate charges(a)	(593)	6	(587)	(623)	—	(623)	36
Interest, net(a)	(1,513)	(11)	(1,524)	(1,492)	(26)	(1,518)	(6)
Income before income taxes	3,335	125	3,460	2,219	1,711	3,930	(470)
Income tax expense(b)	(710)	(37)	(747)	(369)	(491)	(860)	113
Net income	2,625	88	2,713	1,850	1,220	3,070	(357)
Net income attributable to noncontrolling interests(a)	(77)	—	(77)	(66)	—	(66)	(11)
Net income attributable to Kinder Morgan, Inc.	$ 2,548	$ 88	$ 2,636	$ 1,784	$ 1,220	$ 3,004	$ (368)

(a) For a more detailed discussion of these Certain Items, see the footnotes to the tables within "*—Segment Earnings Results*" *and* "*—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests*" below.
(b) The combined net effect of the income tax Certain Items represents the income tax provision on Certain Items plus discrete income tax items.

Net income attributable to Kinder Morgan, Inc. adjusted for Certain Items (Adjusted Earnings) decreased by $368 million from the prior year. The decrease was primarily due to lower Adjusted Segment EBDA contributions of $668 million from our Natural Gas Pipelines business segment's Midstream region (see "*—Segment Earnings Results—Natural Gas Pipelines*" further below) which was impacted by the February 2021 winter storm (and therefore largely nonrecurring) partially offset by lower income tax expense related to the reduction in earnings.

Non-GAAP Financial Measures

Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF

	Year Ended December 31,	
	2022	**2021**
	(In millions)	
Net income attributable to Kinder Morgan Inc. (GAAP)	$ 2,548	$ 1,784
Total Certain Items	88	1,220
Adjusted Earnings(a)	2,636	3,004
DD&A and amortization of excess cost of equity investments for DCF(b)	2,534	2,481
Income tax expense for DCF(a)(b)	822	943
Cash taxes(b)	(83)	(69)
Sustaining capital expenditures(b)	(901)	(864)
Other items(c)	(38)	(35)
DCF	$ 4,970	$ 5,460

Adjusted Segment EBDA to Adjusted EBITDA to DCF

	Year Ended December 31,	
	2022	**2021**
	(In millions, except per share amounts)	
Natural Gas Pipelines	$ 4,942	$ 5,463
Products Pipelines	1,107	1,117
Terminals	975	950
CO_2	808	754
Adjusted Segment EBDA(a)	7,832	8,284
General and administrative and corporate charges(a)	(587)	(623)
Joint venture DD&A and income tax expense(a)(b)	348	351
Net income attributable to noncontrolling interests(a)	(77)	(66)
Adjusted EBITDA	7,516	7,946
Interest, net(a)	(1,524)	(1,518)
Cash taxes(b)	(83)	(69)
Sustaining capital expenditures(b)	(901)	(864)
Other items(c)	(38)	(35)
DCF	$ 4,970	$ 5,460
Adjusted Earnings per share	$ 1.16	$ 1.32
Weighted average shares outstanding for dividends(d)	2,271	2,278
DCF per share	$ 2.19	$ 2.40
Declared dividends per share	$ 1.11	$ 1.08

(a) Amounts are adjusted for Certain Items. See tables included in *"—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted EBITDA"* and *"—Supplemental Information"* below.
(b) Includes or represents DD&A, income tax expense, cash taxes and/or sustaining capital expenditures (as applicable for each item) from joint ventures. See tables included in *"—Supplemental Information"* below.
(c) Includes pension contributions, non-cash pension expense and non-cash compensation associated with our restricted stock program.
(d) Includes restricted stock awards that participate in dividends.

Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted EBITDA

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(In millions)	
Net income attributable to Kinder Morgan, Inc. (GAAP)	$ 2,548	$ 1,784
Certain Items:		
Fair value amortization	(15)	(19)
Legal, environmental and other reserves	51	160
Change in fair value of derivative contracts(a)	57	19
Loss on impairments, divestitures and other write-downs, net(b)	—	1,535
Income tax Certain Items	(37)	(491)
Other	32	16
Total Certain Items(c)	88	1,220
DD&A and amortization of excess cost of equity investments	2,261	2,213
Income tax expense(d)	747	860
Joint venture DD&A and income tax expense(d)(e)	348	351
Interest, net(d)	1,524	1,518
Adjusted EBITDA	$ 7,516	$ 7,946

(a) Gains or losses are reflected in our DCF when realized.

(b) 2021 amount primarily includes a pre-tax non-cash impairment loss of $1,600 million related to our South Texas gathering and processing assets within our Natural Gas Pipelines business segment reported within "(Gain) loss on divestitures and impairments, net" and a pre-tax gain of $206 million associated with the sale of a partial interest in our equity investment in NGPL Holdings LLC, offset partially by a write-down of $117 million on a long-term subordinated note receivable from an equity investee, Ruby, reported within "Other, net" and "Earnings from equity investments," respectively, on the accompanying consolidated statement of income.

(c) 2022 and 2021 amounts include $1 million and $124 million, respectively, reported within "Earnings from equity investments" on our accompanying consolidated statements of income.

(d) Amounts are adjusted for Certain Items. See tables included in *"—Supplemental Information"* and *"—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests"* below.

(e) Represents joint venture DD&A and income tax expense. See table included in *"—Supplemental Information"* below.

	Year Ended December 31,	
	2022	2021
	(In millions)	
DD&A (GAAP)	$ 2,186	$ 2,135
Amortization of excess cost of equity investments (GAAP)	75	78
DD&A and amortization of excess cost of equity investments	2,261	2,213
Joint venture DD&A	273	268
DD&A and amortization of excess cost of equity investments for DCF	$ 2,534	$ 2,481
Income tax expense (GAAP)	$ 710	$ 369
Certain Items	37	491
Income tax expense(a)	747	860
Unconsolidated joint venture income tax expense(a)(b)	75	83
Income tax expense for DCF(a)	$ 822	$ 943
Additional joint venture information		
Unconsolidated joint venture DD&A	$ 323	$ 312
Less: Consolidated joint venture partners' DD&A	50	44
Joint venture DD&A	273	268
Unconsolidated joint venture income tax expense(a)(b)	75	83
Joint venture DD&A and income tax expense(a)	$ 348	$ 351
Unconsolidated joint venture cash taxes(b)	$ (70)	$ (60)
Unconsolidated joint venture sustaining capital expenditures	$ (148)	$ (116)
Less: Consolidated joint venture partners' sustaining capital expenditures	(8)	(9)
Joint venture sustaining capital expenditures	$ (140)	$ (107)

(a) Amounts are adjusted for Certain Items.
(b) Amounts are associated with our Citrus, NGPL and Products (SE) Pipe Line equity investments.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,	
	2022	2021
	(In millions, except operating statistics)	
Revenues	$ 12,686	$ 11,709
Operating expenses	(8,562)	(7,000)
Gain (loss) on divestitures and impairments, net	10	(1,599)
Other income	3	2
Earnings from equity investments	683	487
Other, net	(19)	216
Segment EBDA	**4,801**	**3,815**
Certain Items(a)	141	1,648
Adjusted Segment EBDA	$ 4,942	$ 5,463

Change from prior period	Increase/(Decrease)
Segment EBDA	**$ 986**
Adjusted Segment EBDA	$ (521)

Volumetric data(b)		
Transport volumes (BBtu/d)	39,064	38,577
Sales volumes (BBtu/d)	2,482	2,473
Gathering volumes (BBtu/d)	3,046	2,749
NGLs (MBbl/d)	30	29

(a) For more detail of these Certain Items, see the discussion of changes in Segment EBDA below.
(b) Joint venture throughput is reported at our ownership share. Volumes for acquired pipelines are included and volumes for assets sold are excluded for all periods presented, however, EBDA contributions from acquisitions are included only for the periods subsequent to their acquisition.

Below are the changes in Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	Segment EBDA		
	2022	2021	increase/(decrease)
	(In millions)		
Midstream	$ 1,441	$ 442	$ 999
East	2,502	2,510	(8)
West	858	863	(5)
Total Natural Gas Pipelines	$ 4,801	$ 3,815	$ 986

The changes in Segment EBDA for our Natural Gas Pipelines business segment in the comparable years of 2022 and 2021 are explained by the following discussion:

- A $999 million (226%) increase in Midstream was affected by the following items for 2022 and 2021: (i) a pre-tax non-cash asset impairment loss of $1,600 million in the 2021 period related to our South Texas gathering and processing assets; (ii) an increase in expense in the 2021 period related to a certain litigation matter; and (iii) an increase in revenues and costs of sales period over period related to the impacts of non-cash mark-to-market derivative contracts used to hedge forecasted commodity sales and purchases, all of which we treated as Certain Items.

In addition, Midstream's Segment EBDA was unfavorably impacted by lower realized gas sales margins of $781 million on our Texas intrastate natural gas pipeline operations and $77 million on our South Texas assets largely driven by higher commodity prices related to the February 2021 winter storm partially offset by (i) higher volumes on our KinderHawk assets; (ii) higher commodity sales margins driven by higher prices on our Altamont asset; and (iii) higher earnings on our Oklahoma assets from lower costs of sales due to higher commodity prices in 2021 on certain purchase contracts as a result of the February 2021 winter storm. Overall, Midstream's revenue changes are partially offset by corresponding changes in costs of sales.

- An $8 million (—%) decrease in the East Region was affected by a pre-tax gain in the 2021 period associated with the sale of a partial interest in our equity investment in NGPL Holdings which we treated as a Certain Item.

  In addition, East Region's Segment EBDA was favorably impacted by (i) our July 2021 acquisition of the Stagecoach assets; (ii) higher equity earnings from MEP driven by new customer contracts in 2022; (iii) increased earnings from KMLP reflecting a new LNG customer contract; and (iv) higher equity earnings from SNG as a result of increased demand for services; partially offset by decreased earnings on TGP driven by higher operating expenses due in part to higher pipeline integrity costs partially offset by higher park and loan revenues.

- A $5 million (1%) decrease in the West Region was primarily impacted by lower earnings from CIG driven by lower revenues resulting from a rate case settlement and from EPNG driven by increased operating expenses and decreased revenues due to lower commodity and park and loan volumes which resulted from a partial pipeline outage, partially offset by an increase in gas sales margin.

  In addition, the West Region's Segment EBDA was affected by the following items for 2022 and 2021: (i) a write-down on a long-term subordinated note receivable from our equity investee, Ruby, in 2021; (ii) an increase in operating expenses in the 2022 period related to litigation reserves and other costs associated with the EPNG pipeline rupture; and (iii) an increase in expense in the 2022 period resulting from a payment associated with the bankruptcy settlement involving our equity investee, Ruby, all of which we treated as Certain Items.

Below are the changes in Adjusted Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	2022			2021			
	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Adjusted Segment EBDA increase/(decrease)
				(In millions)			
Midstream	$ 1,441	$ 62	$ 1,503	$ 442	$ 1,729	$ 2,171	$ (668)
East	2,502	1	2,503	2,510	(199)	2,311	192
West	858	78	936	863	118	981	(45)
Total Natural Gas Pipelines	$ 4,801	$ 141	$ 4,942	$ 3,815	$ 1,648	$ 5,463	$ (521)

Products Pipelines

	Year Ended December 31, 2022	2021
	(In millions, except operating statistics)	
Revenues	$ 3,418	$ 2,245
Operating expenses	(2,391)	(1,239)
Gain on divestitures and impairments, net	12	—
Earnings from equity investments	68	57
Other, net	—	1
Segment EBDA	**1,107**	**1,064**
Certain Items(a)	—	53
Adjusted Segment EBDA	$ 1,107	$ 1,117

Change from prior period	Increase/(Decrease)
Segment EBDA	**$ 43**
Adjusted Segment EBDA	$ (10)

Volumetric data(b)	2022	2021
Gasoline(c)	978	987
Diesel fuel	367	390
Jet fuel	264	223
Total refined product volumes	1,609	1,600
Crude and condensate	471	498
Total delivery volumes (MBbl/d)	2,080	2,098

(a) For more detail of these Certain Items, see the discussion of changes in Segment EBDA below.
(b) Joint venture throughput is reported at our ownership share.
(c) Volumes include ethanol pipeline volumes.

Below are the changes in Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	Segment EBDA 2022	2021	increase/(decrease)
	(In millions)		
West Coast Refined Products	$ 511	$ 448	$ 63
Southeast Refined Products	265	258	7
Crude and Condensate	331	358	(27)
Total Products Pipelines	$ 1,107	$ 1,064	$ 43

The changes in Segment EBDA for our Products Pipelines business segment in the comparable years of 2022 and 2021 are explained by the following discussion:

- A $63 million (14%) increase in West Coast Refined Products was affected by increased expenses in the 2021 period related to litigation and environmental reserve adjustments which we treated as Certain Items.

  In addition, West Coast Refined Products Segment EBDA was further impacted by a gain on sale of land at Calnev and increased earnings driven by higher revenues on our West Coast terminals from higher volumes and rates, partially offset by lower earnings on our Pacific operations resulting from higher integrity management expenses partially offset by higher revenues driven by increased transportation rates.

- A $7 million (3%) increase in Southeast Refined Products was primarily due to an increase in equity earnings from Products (SE) Pipe Line primarily due to higher revenues as a result of increased volumes partially offset by higher pipeline integrity costs. Overall, revenues from our Transmix processing operations were largely offset by corresponding costs of sales.
- A $27 million (8%) decrease in Crude and Condensate was primarily due to lower earnings from our Bakken Crude assets due to lower volumes on our Double H pipeline and from our Kinder Morgan Crude & Condensate pipeline driven primarily by lower deficiency revenues, partially offset by higher earnings from our KM Condensate Processing facility reflecting increased revenues due to higher volumes and rate escalations. Our Crude and Condensate business also had higher revenues of $974 million with a corresponding increase in cost of sales, resulting from increased marketing activities.

Below are the changes in Adjusted Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	2022			2021			
	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Adjusted Segment EBDA increase/(decrease)
				(In millions)			
West Coast Refined Products	$ 511	$ —	$ 511	$ 448	$ 53	$ 501	$ 10
Southeast Refined Products	265	—	265	258	—	258	7
Crude and Condensate	331	—	331	358	—	358	(27)
Total Products Pipelines	$ 1,107	$ —	$ 1,107	$ 1,064	$ 53	$ 1,117	$ (10)

Terminals

	Year Ended December 31,	
	2022	2021
	(In millions, except operating statistics)	
Revenues	$ 1,792	$ 1,715
Operating expenses	(853)	(793)
Gain (loss) on divestitures and impairments, net	9	(36)
Other income	5	4
Earnings from equity investments	14	15
Other, net	8	3
Segment EBDA	**975**	**908**
Certain Items(a)	—	42
Adjusted Segment EBDA	$ 975	$ 950

Change from prior period	Increase/(Decrease)
Segment EBDA	**$ 67**
Adjusted Segment EBDA	$ 25

Volumetric data(b)		
Liquids leasable capacity (MMBbl)	77.8	77.8
Liquids utilization %(c)	93.3 %	94.8 %
Bulk transload tonnage (MMtons)	53.2	51.3

(a) For more detail of these Certain Items, see the discussion of changes in Segment EBDA below.
(b) Volumes for facilities divested, idled, and/or held for sale are excluded for all periods presented.
(c) The ratio of our tankage capacity in service to liquids leasable capacity.

For purposes of the following tables and related discussions, the results of operations of our terminals held for sale or divested, including any associated gain or loss on sale, are reclassified for all periods presented from the historical region and included within the All others group.

Below are the changes in Segment EBDA between 2022 and 2021:

<u>Year Ended December 31, 2022 versus Year Ended December 31, 2021</u>

	Segment EBDA		
	2022	2021	increase/(decrease)
	(In millions)		
Mid Atlantic	$ 101	$ 63	$ 38
Lower River	74	51	23
Gulf Central	134	122	12
Gulf Liquids	285	300	(15)
Northeast	92	107	(15)
Marine operations	146	151	(5)
All others (including intrasegment eliminations)	143	114	29
Total Terminals	$ 975	$ 908	$ 67

The changes in Segment EBDA for our Terminals business segment in the comparable years of 2022 and 2021 are explained by the following discussion:

- A $38 million (60%) increase in the Mid Atlantic terminals was primarily due to higher handling rates and coal volumes at our Pier IX facility.
- A $23 million (45%) increase in the Lower River terminals was primarily due to higher deficiency revenues from a coal customer and the non-recurring impact associated with 2021's Hurricane Ida, including lower revenues and higher operating expenses recognized in the 2021 period. The non-recurring impact on 2021 operating expenses associated with Hurricane Ida was treated by us as a Certain Item.
- A $12 million (10%) increase in the Gulf Central terminals was primarily due to higher volumes for petroleum coke handling activities, owing largely to refinery outages in the 2021 period associated with the February 2021 winter storm and lower property tax expense at Battleground Oil Specialty Terminal Company LLC.
- A $15 million (5%) decrease in the Gulf Liquids region was primarily due to re-contracting at lower rates and higher property tax expense partially offset by contractual rate escalations.
- A $15 million (14%) decrease in the Northeast terminals was primarily driven by decreased revenues associated with lower utilization and lower rates on re-contracted tank positions at our Carteret and Perth Amboy facilities.
- A $5 million (3%) decrease in Marine operations was primarily due to lower average charter rates partially offset by higher fleet utilization.
- In addition, other Terminals Segment EBDA was further affected in the 2021 period by pre-tax non-cash impairment losses related to the planned divestiture of our Wilmington terminal and the sale of our interest in Kinder Morgan Resources LLC, both of which we treated as Certain Items.

Below are the changes in Adjusted Segment EBDA between 2022 and 2021:

<u>Year Ended December 31, 2022 versus Year Ended December 31, 2021</u>

	2022			2021			
	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Adjusted Segment EBDA increase/(decrease)
				(In millions)			
Mid Atlantic	$ 101	$ —	$ 101	$ 63	$ —	$ 63	$ 38
Lower River	74	—	74	51	8	59	15
Gulf Central	134	—	134	122	—	122	12
Gulf Liquids	285	—	285	300	—	300	(15)
Northeast	92	—	92	107	—	107	(15)
Marine operations	146	—	146	151	—	151	(5)
All others (including intrasegment eliminations)	143	—	143	114	34	148	(5)
Total Terminals	$ 975	$ —	$ 975	$ 908	$ 42	$ 950	$ 25

CO_2

		Year Ended December 31,		
		2022		2021
		(In millions, except operating statistics)		
Revenues	$	1,334	$	1,009
Operating expenses		(554)		(289)
Gain on divestitures and impairments, net		1		8
Earnings from equity investments		38		32
Segment EBDA		**819**		**760**
Certain Items(a)		(11)		(6)
Adjusted Segment EBDA	$	808	$	754

Change from prior period	Increase/(Decrease)	
Segment EBDA	**$**	**59**
Adjusted Segment EBDA	$	54

Volumetric data				
SACROC oil production		19.92		19.88
Yates oil production		6.52		6.57
Other		2.75		3.25
Total oil production, net (MBbl/d)(b)		29.19		29.70
NGL sales volumes, net (MBbl/d)(b)		9.40		9.38
CO_2 sales volumes, net (Bcf/d)		0.36		0.38
Realized weighted average oil price ($ per Bbl)(c)	$	66.78	$	52.71
Realized weighted average NGL price ($ per Bbl)	$	39.59	$	25.39

(a) For more detail of these Certain Items, see the discussion of changes in Segment EBDA below.
(b) Net of royalties and outside working interests.
(c) Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $96.36 per barrel and $68.47 per barrel in 2022 and 2021, respectively.

Below are the changes in Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

		Segment EBDA				
		2022		2021		increase/(decrease)
				(In millions)		
Oil and Gas Producing activities	$	553	$	507	$	46
Source and Transportation activities		247		245		2
Subtotal		800		752		48
Energy Transition Ventures		19		8		11
Total CO_2	$	819	$	760	$	59

The changes in Segment EBDA for our CO_2 business segment in the comparable years of 2022 and 2021 are explained by the following discussion:

- A $46 million (9%) increase in Oil and Gas Producing activities primarily due to higher realized crude oil and NGL prices which increased revenues by $203 million, a 2021 settlement of $38 million for a terminated affiliate purchase contract with Source and Transportation activities partially offset by higher operating expenses of $186 million mainly driven by the benefit realized in the 2021 period from returning power to the grid by curtailing oil production during the February 2021 winter storm.

In addition, Oil and Gas Producing activities Segment EBDA was favorably affected in 2022 and 2021 by changes in revenues related to non-cash mark-to-market derivative hedge contracts which we treated as Certain Items.

- A $2 million (1%) increase in Source and Transportation activities primarily due to increased revenues of $51 million related to higher CO_2 sales prices partially offset by a 2021 settlement of $38 million for a terminated affiliate sales contract with Oil and Gas Producing activities and decreased revenues related to lower CO_2 sales volumes.

  In addition, Source and Transportation activities was unfavorably impacted by a gain on sale of an asset in 2021 which we treated as a Certain Item.

Below are the changes in Adjusted Segment EBDA between 2022 and 2021:

Year Ended December 31, 2022 versus Year Ended December 31, 2021

	2022			2021			
	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Segment EBDA (GAAP)	Certain Items	Adjusted Segment EBDA	Adjusted Segment EBDA increase/(decrease)
				(In millions)			
Oil and Gas Producing activities	$ 553	$ (11)	$ 542	$ 507	$ 4	$ 511	$ 31
Source and Transportation activities	247	—	247	245	(10)	235	12
Subtotal	800	(11)	789	752	(6)	746	43
Energy Transition Ventures	19	—	19	8	—	8	11
Total CO_2	$ 819	$ (11)	$ 808	$ 760	$ (6)	$ 754	$ 54

We believe that our existing hedge contracts in place within our CO_2 business segment substantially mitigate commodity price sensitivities in the near-term and to lesser extent over the following few years from price exposure. Below is a summary of our CO_2 business segment hedges outstanding as of December 31, 2022.

	2023	2024	2025	2026
Crude Oil(a)				
Price ($ per Bbl)	$ 64.19	$ 61.66	$ 61.76	$ 65.72
Volume (MBbl/d)	22.30	14.14	9.72	4.10
NGLs				
Price ($ per Bbl)	$ 59.13			
Volume (MBbl/d)	3.08			
Midland-to-Cushing Basis Spread				
Price ($ per Bbl)	$ 0.97			
Volume (MBbl/d)	17.96			

(a) Includes West Texas Intermediate hedges.

DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Year Ended December 31,		
	2022	**2021**	**Earnings increase/(decrease)**
		(In millions)	
DD&A (GAAP)	$ (2,186)	$ (2,135)	$ (51)
General and administrative (GAAP)	$ (637)	$ (655)	$ 18
Corporate benefit	44	32	12
Certain Items(a)	6	—	6
General and administrative and corporate charges(b)	$ (587)	$ (623)	$ 36
Interest, net (GAAP)	$ (1,513)	$ (1,492)	$ (21)
Certain Items(a)	(11)	(26)	15
Interest, net(b)	$ (1,524)	$ (1,518)	$ (6)
Net income attributable to noncontrolling interests (GAAP)	$ (77)	$ (66)	$ (11)
Certain Items(a)	—	—	—
Net income attributable to noncontrolling interests(b)	$ (77)	$ (66)	$ (11)

(a) For more detailed discussions of these Certain Items, see the discussions of changes in DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests below.
(b) Amounts are adjusted for Certain Items.

We had a favorable change of $18 million in general and administrative expenses and a favorable change of $12 million in our corporate benefit in 2022 when compared to 2021. The combined changes were primarily due to higher capitalized costs of $24 million, reflecting higher capital spending, and lower benefit-related and pension costs of $18 million partially offset by $9 million of higher labor, travel and legal costs. In addition, the combined changes included the unfavorable impact of an increase in costs of $6 million associated with the Ruby bankruptcy which we treated as a Certain Item.

In the table above, we report our interest expense as "net," meaning that we have subtracted interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense, net increased $21 million in 2022 when compared to 2021 primarily due to higher realized LIBOR/SOFR rates associated with interest rate swaps partially offset by lower average long-term debt balances at slightly lower weighted average rates.

The increase in interest expense was further impacted by (i) non-cash differences between the change in fair value of interest rate swaps not designated as accounting hedges and the change in fair value of hedged debt, primarily related to our floating-to-fixed LIBOR/SOFR interest rate swaps, and (ii) non-cash debt fair value adjustments associated with acquisitions, both of which were treated by us as Certain Items

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2022 and 2021, approximately 20% and 21%, respectively, of the principal amount of our debt balances were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. The percentage at December 31, 2022 includes $1,250 million of variable-to-fixed interest rate derivative contracts which expire in December 2023. The percentage at December 31, 2021 excludes $4,860 million of variable-to-fixed interest rate derivative contracts which became effective January 4, 2022 and hedged our exposure through 2022. For more information on our interest rate swaps, see Note 14 "Risk Management—*Interest Rate Risk Management*" to our consolidated financial statements.

Net income attributable to noncontrolling interests represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not owned by us.

Income Taxes

	Year Ended December 31,		
	2022	**2021**	**Increase**
		(In millions)	
Income tax expense	$ 710	$ 369	$ 341

The increase in income tax expense is due primarily to (i) higher pretax book income in 2022; (ii) the release of a valuation allowance related to our investment in NGPL in 2021; (iii) the Enhanced Oil Recovery Credit in 2021; and (iv) lower dividend-received deductions in 2022.

On August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was enacted into law. The IRA contains significant U.S. federal income tax law changes, including the addition of a corporate alternative minimum tax imposed at a rate of fifteen percent (15%) on our global adjusted financial statement income effective as of January 1, 2023. Based on current guidance, we do not expect the IRA to have a material adverse impact on our business, results of operations or financial position.

Liquidity and Capital Resources

General

As of December 31, 2022, we had $745 million of "Cash and cash equivalents," a decrease of $395 million from December 31, 2021. Additionally, as of December 31, 2022, we had borrowing capacity of approximately $3.9 billion under our credit facilities (discussed below in "*—Short-term Liquidity*"). As discussed further below, we believe our cash flows from operating activities, cash position and remaining borrowing capacity on our credit facilities are more than adequate to allow us to manage our day-to-day cash requirements and anticipated obligations.

We have consistently generated substantial cash flow from operations, providing a source of funds of $4,967 million and $5,708 million in 2022 and 2021, respectively. The year-to-year decrease is discussed below in "*—Cash Flows—Operating Activities.*" We primarily rely on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, dividend payments, and our growth capital expenditures; however, we may access the debt capital markets from time to time to refinance our maturing long-term debt and finance incremental investments, if any.

Our board of directors declared a quarterly dividend of $0.2775 per share for the fourth quarter of 2022, consistent with previous quarters in 2022. The total of the dividends declared for 2022 of $1.11 represents a 3% increase over total dividends declared for 2021.

On February 23, 2022, EPNG issued in a private offering $300 million aggregate principal amount of 3.50% senior notes due 2032 and received net proceeds of $298 million after discount and issuance costs.

On August 3, 2022, we issued in a registered offering two series of senior notes consisting of $750 million aggregate principal amount of 4.80% senior notes due 2033 and $750 million aggregate principal amount of 5.45% senior notes due 2052 and received combined net proceeds of $1,484 million. We used a portion of the proceeds to repay short-term borrowings and for general corporate purposes.

During the first quarter of 2022, upon maturity, we repaid EPNG's 8.625% senior notes, our 4.15% corporate senior notes, and the 1.50% series of our Euro denominated debt. During the second quarter 2022, we repaid $1 billion of our 3.95% senior notes using short-term borrowings. The short-term borrowings were repaid in the third quarter 2022 with proceeds from the August 2022 senior note issuances.

On January 17, 2023, we repaid $1 billion of our 3.15% and $250 million of our floating rate senior notes using cash on hand and short-term borrowings. On January 31, 2023, we issued in a registered offering $1.5 billion aggregate principal amount of 5.20% senior notes due 2033 for net proceeds of $1,485 million, which were used to repay short-term borrowings, maturing debt and for general corporate purposes.

Short-term Liquidity

As of December 31, 2022, our principal sources of short-term liquidity are (i) cash from operations; and (ii) our combined $4.0 billion of credit facilities with an available capacity of approximately $3.9 billion and an associated $3.5 billion commercial paper program. The loan commitments under our credit facilities can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Commercial paper borrowings reduce borrowings allowed under our credit facilities and letters of credit reduce borrowings allowed under our $3.5 billion credit facility. On December 15, 2022, we amended our credit facilities to provide for, among other things, the replacement of LIBOR-based provisions with term SOFR provisions, updated related benchmark replacement provisions and the extension of the maturity date on our $3.5 billion credit facility from August 2026 to August 2027. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facilities and, as previously discussed, have consistently generated strong cash flows from operations.

As of December 31, 2022, our $3,385 million of short-term debt consisted primarily of senior notes that mature in the next twelve months. We intend to fund our debt as it becomes due, primarily through credit facility borrowings, commercial paper borrowings, cash flows from operations, and/or issuing new long-term debt. Our short-term debt balance as of December 31, 2021 was $2,646 million.

We had working capital (defined as current assets less current liabilities) deficits of $3,127 million and $1,992 million as of December 31, 2022 and 2021, respectively. From time to time, our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we may periodically replace with long-term financing and/or pay down using retained cash from operations. The overall $1,135 million unfavorable change from year-end 2021 was primarily due to (i) a $739 million increase in current debt, primarily related to senior notes that mature in the next twelve months; (ii) a $395 million decrease in cash and cash equivalents, which was used to repay a portion of senior notes that matured in the first quarter of 2022; and (iii) unfavorable net short-term fair value adjustments of $276 million on derivative contract assets and liabilities in 2022, offset partially by (i) a $156 million decrease in accrued contingencies; (ii) a $72 million increase in inventories, primarily products inventories; (iii) a $44 million net favorable change in our accounts receivables and payables, and (iv) a $42 million increase in restricted deposits. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities (discussed below in "*—Long-term Financing*" and "*—Capital Expenditures*").

We employ a centralized cash management program for our U.S.-based bank accounts that concentrates the cash assets of our wholly owned subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. These programs provide that funds in excess of the daily needs of our wholly owned subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to KMI other than restrictions that may be contained in agreements governing the indebtedness of those entities.

Credit Ratings and Capital Market Liquidity

We believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. Generally, we anticipate re-financing maturing long-term debt obligations in the debt capital markets and are therefore subject to certain market conditions which could result in higher costs or negatively affect our and/or our subsidiaries' credit ratings. A decrease in our credit ratings could negatively impact our borrowing costs and could limit our access to capital.

As of December 31, 2022, our short-term corporate debt ratings were A-2, Prime-2 and F2 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2022.

Rating agency	Senior debt rating	Outlook
Standard and Poor's	BBB	Stable
Moody's Investor Services	Baa2	Stable
Fitch Ratings, Inc.	BBB	Stable

Long-term Financing

Our equity consists of Class P common stock with a par value of $0.01 per share. We do not expect to need to access the equity capital markets to fund our discretionary capital investments for the foreseeable future. See also "*—Dividends and Stock Buy-back Program*" below for additional discussion related to our dividends and stock buy-back program.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. In addition, from time to time, our subsidiaries issue long-term debt securities. Furthermore, we and almost all of our direct and indirect wholly owned domestic subsidiaries are parties to a cross guaranty wherein each party guarantees each other party's debt. See "*—Summarized Combined Financial Information for Guarantee of Securities of Subsidiaries*. As of December 31, 2022 and 2021, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $28,288 million and $29,772 million, respectively.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping a portion of the fixed rate interest payments for variable rate interest payments and through the issuance of commercial paper or credit facility borrowings.

For additional information about our outstanding senior notes and debt-related transactions in 2022, see Note 9 "Debt" to our consolidated financial statements. For information about our interest rate risk, see Item 7A. "*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*"

Counterparty Creditworthiness

Some of our customers or other counterparties may experience severe financial problems that may have a significant impact on their creditworthiness. These financial problems may arise from current global economic conditions, continued volatility of commodity prices or otherwise. In such situations, we utilize, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these counterparties. While we believe we have taken reasonable measures to protect against counterparty credit risk, we cannot provide assurance that one or more of our customers or other counterparties will not become financially distressed and will not default on their obligations to us. The balance of our allowance for credit losses as of both December 31, 2022 and 2021, was $1 million, reflected in "Other current assets" on our consolidated balance sheets.

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. Additionally, we distinguish between capital expenditures as follows:

Type of Expenditure	**Physical Determination of Expenditure**
Sustaining capital expenditures	• Maintain throughput or capacity
Expansion capital expenditures (discretionary capital expenditures)(a)	• Increase throughput or capacity (i.e., production capacity) from that which existed immediately prior to the making or acquisition of additions or improvements

(a) Not included in calculating DCF (see "*—Results of Operations—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF*").

Budgeting of maintenance capital expenditures, which we refer to as sustaining capital expenditures, is done annually on a bottom-up basis. For each of our assets, we budget for and make those sustaining capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional sustaining capital expenditures that we expect to produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as sustaining capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion. The classification has an impact on DCF because capital expenditures that are classified as expansion capital expenditures are not deducted from DCF, while those classified as sustaining capital expenditures are.

Our capital expenditures for the year ended December 31, 2022, and the amount we expect to spend for 2023 to sustain our assets and grow our business are as follows:

	2022	Expected 2023
	(In millions)	
Sustaining capital expenditures(a)(b)	$ 901	$ 1,002
Discretionary capital investments(b)(c)(d)	1,709	2,138

(a) 2022 and Expected 2023 amounts include $140 million and $145 million, respectively, for sustaining capital expenditures from unconsolidated joint ventures, reduced by consolidated joint venture partners' sustaining capital expenditures. See table included in "*Non-GAAP Financial Measures—Supplemental Information*."
(b) 2022 combined sustaining and discretionary amounts include $96 million due to increases in accrued capital expenditures and contractor retainage and net changes in other.
(c) 2022 amount includes $264 million of our contributions to certain unconsolidated joint ventures for capital investments and $489 million for our acquisitions of Mas Ranger and NANR.
(d) Amounts include our actual or estimated contributions to certain unconsolidated joint ventures, net of actual or estimated contributions from certain partners in non-wholly owned consolidated subsidiaries for capital investments.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 13 "Commitments and Contingent Liabilities" to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 7 "Investments" to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

The table below provides a summary of our material cash requirements.

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In millions)		
Contractual obligations:					
Debt borrowings-principal payments(a)	$ 31,673	$ 3,385	$ 3,491	$ 1,992	$ 22,805
Interest payments(b)	21,234	1,616	2,900	2,689	14,029
Lease obligations(c)	375	58	90	61	166
Pension and OPEB plans(d)	469	50	31	32	356
Transportation, volume and storage agreements(e)	661	157	267	131	106
Other obligations(f)	341	90	105	38	108
Total	$ 54,753	$ 5,356	$ 6,884	$ 4,943	$ 37,570
Other commercial commitments:					
Standby letters of credit(g)	$ 153	$ 81	$ 72		
Capital expenditures(h)	$ 527	$ 527			

(a) See Note 9 “Debt” to our consolidated financial statements.

(b) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31, 2022.

(c) Represents commitments pursuant to the terms of operating lease agreements as of December 31, 2022.

(d) Represents the amount by which the benefit obligations exceeded the fair value of plan assets at year-end for pension and OPEB plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets. The payments by period include expected contributions in 2023 and estimated benefit payments for underfunded plans in the other years.

(e) Primarily represents transportation agreements of $298 million, storage agreements for capacity of $159 million and NGL volume agreements of $155 million.

(f) Primarily includes (i) rights-of-way obligations; and (ii) environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we will perform remediation activities. These environmental liabilities are included within “Other current liabilities” and “Other long-term liabilities and deferred credits” in our consolidated balance sheet as of December 31, 2022.

(g) The $153 million in letters of credit outstanding as of December 31, 2022 consisted of the following (i) $54 million under six letters of credit for insurance purposes; (ii) a $46 million letter of credit supporting our International Marine Terminals Partnership Plaquemines Bond; (iii) a $24 million letter of credit supporting our Kinder Morgan Operating LLC “B” tax-exempt bonds; and (iv) a combined $30 million in twenty-nine letters of credit supporting environmental and other obligations of us and our subsidiaries.

(h) Represents commitments for the purchase of plant, property and equipment as of December 31, 2022.

Cash Flows

The following table summarizes our net cash flows provided by (used in) operating, investing and financing activities between 2022 and 2021.

	Year Ended December 31,		
	2022	2021	Changes
		(In millions)	
Net Cash Provided by (Used in)			
Operating activities	$ 4,967	$ 5,708	$ (741)
Investing activities	(2,175)	(2,305)	130
Financing activities	(3,145)	(3,465)	320
Net Decrease in Cash, Cash Equivalents and Restricted Deposits	$ (353)	$ (62)	$ (291)

Operating Activities

$741 million less cash provided by operating activities in the comparable years of 2022 and 2021 is explained by the following discussion.

- a $502 million decrease in cash after adjusting the $775 million increase in net income by $1,277 million for the combined effects of the period-to-period net changes in non-cash items. This overall cash decrease primarily resulted from the benefit recognized in 2021 for largely nonrecurring earnings related to the February 2021 winter storm (see discussion above in "—Results of Operations"); and
- a $239 million decrease in cash associated with net changes in working capital items and other non-current assets and liabilities. The decrease was primarily driven by unfavorable changes due to the timing of trade payments in accounts payable and payments from reserves in 2022 compared with 2021 associated with litigation matters.

Investing Activities

$130 million less cash used in investing activities in the comparable years of 2022 and 2021 is explained by the following discussion.

- a $1,060 million decrease in expenditures for the acquisition of assets and investments, net of cash acquired, primarily driven by a combined $487 million of net cash used for our acquisitions of Mas Ranger, LLC and NANR in 2022, compared with a combined $1,538 million of net cash used for the acquisitions of Stagecoach and Kinetrex in 2021; See Note 3 "Acquisitions and Divestitures" to our consolidated financial statements for further information regarding these two acquisitions; partially offset by,
- a $400 million decrease in proceeds from sales of property, plant and equipment, investments, and other assets, net of removal costs primarily due to $412 million received from the sale of a partial interest in our equity investment in NGPL Holdings in 2021;
- a $340 million increase in capital expenditures reflecting an overall increase of expansion capital projects for most of our business segments in 2022 over the comparative 2021 period; and
- a $191 million increase in cash used for contributions to equity investees driven primarily by higher contributions in 2022 compared with 2021 to SNG associated with a debt payment.

Financing Activities

$320 million less cash used in financing activities in the comparable years of 2022 and 2021 is explained by the following discussion.

- $557 million of net proceeds received from the sale of a 25.5% ownership interest in ELC in 2022; and
- a $197 million net decrease in cash used related to debt activity as a result of lower net debt payments in 2022 compared to 2021; partially offset by,
- $368 million of cash used in 2022 for share repurchases under our share buy-back program.

Dividends and Stock Buy-back Program

The table below reflects the declaration of dividends of $1.11 per share for 2022:

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2022	$0.2775	April 20, 2022	May 2, 2022	May 16, 2022
June 30, 2022	0.2775	July 20, 2022	August 1, 2022	August 15, 2022
September 30, 2022	0.2775	October 19, 2022	October 31, 2022	November 15, 2022
December 31, 2022	0.2775	January 18, 2023	January 31, 2023	February 15, 2023

We expect to continue to return additional value to our shareholders in 2023 through our previously announced dividend increase. We plan to increase our dividend by 2% to $1.13 per common share in 2023. On January 18, 2023, our board of directors approved an increase to our stock buy-back program from $2 billion to $3 billion. Since December 2017, in total, we have repurchased approximately 54 million shares of our Class P common stock under the program at an average price of approximately $17.40 per share for approximately $943 million, leaving a remaining capacity of $2.1 billion. For information on our equity buy-back program, see Note 11 "Stockholders' Equity" to our consolidated financial statements.

The actual amount of dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A. "*Risk Factors—The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.*" All of these matters will be taken into consideration by our board of directors when declaring dividends.

Our dividends are not cumulative. Consequently, if dividends on our stock are not paid at the intended levels, our stockholders are not entitled to receive those payments in the future. Our dividends generally will be paid on or about the 15th day of each February, May, August and November.

Summarized Combined Financial Information for Guarantee of Securities of Subsidiaries

KMI and certain subsidiaries (Subsidiary Issuers) are issuers of certain debt securities. KMI and substantially all of KMI's wholly owned domestic subsidiaries (Subsidiary Guarantors), are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as subsidiary non-guarantors (Subsidiary Non-Guarantors), the parent issuer, Subsidiary Issuers and Subsidiary Guarantors (the "Obligated Group") are all guarantors of each series of our guaranteed debt (Guaranteed Notes). As a result of the cross guarantee agreement, a holder of any of the Guaranteed Notes issued by KMI or Subsidiary Issuers are in the same position with respect to the net assets, and income of KMI and the Subsidiary Issuers and Guarantors. The only amounts that are not available to the holders of each of the Guaranteed Notes to satisfy the repayment of such securities are the net assets, and income of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for the Obligated Group, we have presented the accompanying supplemental summarized combined income statement and balance sheet information for the Obligated Group based on Rule 13-01 of the SEC's Regulation S-X. Also, see Exhibit 10.14 to this Report "*Cross Guarantee Agreement, dated as of November 26, 2014, among KMI and certain of its subsidiaries, with schedules updated as of December 31, 2022.*"

All significant intercompany items among the Obligated Group have been eliminated in the supplemental summarized combined financial information. The Obligated Group's investment balances in Subsidiary Non-Guarantors have been excluded from the supplemental summarized combined financial information. Significant intercompany balances and activity for the Obligated Group with other related parties, including Subsidiary Non-Guarantors (referred to as "affiliates"), are presented separately in the accompanying supplemental summarized combined financial information.

Excluding fair value adjustments, as of December 31, 2022 and 2021, the Obligated Group had $30,886 million and $31,608 million, respectively, of Guaranteed Notes outstanding.

Summarized combined balance sheet and income statement information for the Obligated Group follows:

	December 31,	
Summarized Combined Balance Sheet Information	**2022**	**2021**
	(In millions)	
Current assets	$ 3,514	$ 3,556
Current assets - affiliates	618	1,233
Noncurrent assets	61,523	61,754
Noncurrent assets - affiliates	516	508
Total Assets	$ 66,171	$ 67,051
Current liabilities	$ 6,612	$ 5,413
Current liabilities - affiliates	707	1,332
Noncurrent liabilities	30,668	32,310
Noncurrent liabilities - affiliates	1,096	1,047
Total Liabilities	39,083	40,102
Kinder Morgan, Inc.'s stockholders' equity	27,088	26,949
Total Liabilities and Stockholders' Equity	$ 66,171	$ 67,051

Summarized Combined Income Statement Information	**Year Ended December 31, 2022**
	(In millions)
Revenues	$ 17,778
Operating income	3,611
Net income	2,175

Recent Accounting Pronouncements

Please refer to Note 19 “Recent Accounting Pronouncements” to our consolidated financial statements for information concerning recent accounting pronouncements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

Generally, our market risk sensitive instruments and positions have been determined to be “other than trading.” Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in energy commodity prices or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in energy commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We enter into certain energy commodity derivative contracts in order to reduce and minimize the risks encountered in the ordinary course of business associated with unfavorable changes in the market price of crude oil, natural gas and NGL. The derivative contracts that we use include exchange-traded and OTC commodity financial instruments, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but whose value is uncertain.

Our hedging strategy involves entering into a financial position intended to offset our physical position, or anticipated position, in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil, natural gas and NGL, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets.

Our policies require that derivative contracts are only entered into with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties’ credit ratings. While it is our policy to enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future.

We measure the risk of price changes in the derivative instrument portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. Because we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities, both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts’ portfolio is offset largely by changes in the value of the underlying physical transactions. A hypothetical 10% movement in the underlying commodity prices would have the following effect on the associated derivative contracts’ estimated fair value:

	As of December 31,	
Commodity derivative	**2022**	**2021**
	(In millions)	
Crude oil	$ 157	$ 135
Natural gas	49	36
NGL	5	8
Total	$ 211	$ 179

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the crude oil, natural gas and NGL portfolios of derivative contracts assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. Fixed-to-variable interest rate swap agreements are entered into for the purpose of converting a portion of the underlying cash flows related to long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Variable-to-fixed interest rate swap agreements are entered into primarily for the purpose of managing our exposure to changes in interest rates on our debt balances that are subject to variable interest rates and adjusting, on a short-term basis, our mix of fixed rate debt and variable rate debt based on changes in market conditions. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, changes in fair value should not have a significant impact on the fixed rate debt. We are generally subject to interest rate risk upon refinancing maturing debt. Below are our debt balances, including debt fair value adjustments, and sensitivity to interest rates:

	December 31, 2022		December 31, 2021	
	Carrying value	Estimated fair value(a)	Carrying value	Estimated fair value(a)
	(In millions)			
Fixed rate debt(b)	$ 31,474	$ 29,756	$ 33,006	$ 37,459
Variable rate debt	$ 314	$ 314	$ 314	$ 316
Notional principal amount of variable-to-fixed interest rate swap agreements(c)	(1,500)		(490)	
Notional principal amount of fixed-to-variable interest rate swap agreements	7,500		7,100	
Debt balances subject to variable interest rates(d)	$ 6,314		$ 6,924	

(a) Fair values were determined using Level 2 inputs.
(b) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2022 and 2021, would result in changes of approximately $1,882 million and $1,614 million, respectively, in the estimated fair values of these instruments.
(c) December 31, 2022 amount includes $1.25 billion of variable-to-fixed interest rate swap agreements that expire in December 2023. December 31, 2021 amount excludes $4.9 billion of variable-to-fixed interest rate swap agreements that became effective January 4, 2022 and expired December 31, 2022.
(d) A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 48 and 47 basis points, respectively, in 2022 and 2021) when applied to our outstanding balance of variable rate debt as of December 31, 2022 and 2021, including adjustments for the notional swap amounts described in the table above, would result in changes of approximately $30 million and $32 million.

As presented in the table above, we monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2022, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 20% of our debt balances were subject to variable interest rates.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 14 “Risk Management” to our consolidated financial statements.

Foreign Currency Risk

As of December 31, 2022, we had a notional principal amount of $543 million of cross-currency swap agreements that effectively convert all of our fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates. These swaps eliminate the foreign currency risk associated with our foreign currency denominated debt.

Item 8. ***Financial Statements and Supplementary Data.***

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Kinder Morgan, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Kinder Morgan, Inc. and its subsidiaries (the “Company”) as of December 31, 2022 and 2021, and the related consolidated statements of income, of comprehensive income, of stockholders’ equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2022, 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill Impairment Assessment

As described in Notes 2 and 8 to the consolidated financial statements, the Company's consolidated goodwill balance was $20 billion as of December 31, 2022. Management evaluates goodwill for impairment on May 31 of each year, or more frequently to the extent events occur or conditions change between annual tests that would indicate a risk of possible impairment at the interim period. Management estimates fair value based on a market approach utilizing forecasted earnings before interest, taxes, depreciation and amortization (EBITDA) and the enterprise value to estimated EBITDA multiples of comparable companies for each reporting unit.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the significant judgment by management when developing the fair value estimate of the reporting units. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management's significant assumptions related to forecasted EBITDA and the enterprise value to estimated EBITDA multiples of comparable companies for each reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment assessment, including controls related to developing the fair value estimate of the reporting units. These procedures also included, among others, testing management's process for developing the fair value estimate of the reporting units; evaluating the appropriateness of the market approach; testing the completeness and accuracy of underlying data used in the market approach, and evaluating the reasonableness of the significant assumptions used by management related to forecasted EBITDA and the enterprise value to estimated EBITDA multiples of comparable companies for each reporting unit. Evaluating management's significant assumptions related to forecasted EBITDA and the enterprise value to estimated EBITDA multiples of comparable companies for each reporting unit involved evaluating whether the assumptions used by management were reasonable considering (i) the current and past performance of the reporting unit; (ii) the consistency with external market and industry data; and (iii) whether these assumptions were consistent with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in the evaluation of the appropriateness of the market approach and the reasonableness of the significant assumption related to the enterprise value to estimated EBITDA multiples of comparable companies for each reporting unit.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 8, 2023

We have served as the Company's auditor since 1997.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per share amounts)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues			
Services	$ 8,145	$ 7,757	$ 7,618
Commodity sales	10,897	8,714	3,891
Other	158	139	191
Total Revenues	19,200	16,610	11,700
Operating Costs, Expenses and Other			
Costs of sales	9,255	6,493	2,545
Operations and maintenance	2,655	2,368	2,475
Depreciation, depletion and amortization	2,186	2,135	2,164
General and administrative	637	655	648
Taxes, other than income taxes	441	426	378
(Gain) loss on divestitures and impairments, net (Note 4)	(32)	1,624	1,932
Other income, net	(7)	(7)	(2)
Total Operating Costs, Expenses and Other	15,135	13,694	10,140
Operating Income	4,065	2,916	1,560
Other Income (Expense)			
Earnings from equity investments	803	591	780
Amortization of excess cost of equity investments	(75)	(78)	(140)
Interest, net	(1,513)	(1,492)	(1,595)
Other, net (Note 3)	55	282	56
Total Other Expense	(730)	(697)	(899)
Income Before Income Taxes	3,335	2,219	661
Income Tax Expense	(710)	(369)	(481)
Net Income	2,625	1,850	180
Net Income Attributable to Noncontrolling Interests	(77)	(66)	(61)
Net Income Attributable to Kinder Morgan, Inc.	$ 2,548	$ 1,784	$ 119
Class P Common Stock			
Basic and Diluted Earnings Per Share	$ 1.12	$ 0.78	$ 0.05
Basic and Diluted Weighted Average Shares Outstanding	2,258	2,266	2,263

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Net income	$ 2,625	$ 1,850	$ 180
Other comprehensive income (loss), net of tax			
Net unrealized (loss) gain from derivative instruments (net of taxes of $92, $131, and $(75), respectively)	(312)	(432)	249
Reclassification into earnings of net derivative instruments loss (gain) to net income (net of taxes of $(95), $(83), and $78, respectively)	320	273	(255)
Benefit plan adjustments (net of taxes of $(1), $(47), and $19, respectively)	1	155	(68)
Total other comprehensive income (loss)	9	(4)	(74)
Comprehensive income	2,634	1,846	106
Comprehensive income attributable to noncontrolling interests	(77)	(66)	(61)
Comprehensive income attributable to KMI	$ 2,557	$ 1,780	$ 45

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions, except share and per share amounts)

	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 745	$ 1,140
Restricted deposits	49	7
Accounts receivable	1,840	1,611
Fair value of derivative contracts	231	220
Inventories	634	562
Other current assets	304	289
Total current assets	3,803	3,829
Property, plant and equipment, net	35,599	35,653
Investments	7,653	7,578
Goodwill	19,965	19,914
Other intangibles, net	1,809	1,678
Deferred income taxes	—	115
Deferred charges and other assets	1,249	1,649
Total Assets	$ 70,078	$ 70,416
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$ 3,385	$ 2,646
Accounts payable	1,444	1,259
Accrued interest	515	504
Accrued taxes	264	270
Fair value of derivative contracts	465	178
Other current liabilities	857	964
Total current liabilities	6,930	5,821
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	28,288	29,772
Debt fair value adjustments	115	902
Total long-term debt	28,403	30,674
Deferred income taxes	623	—
Other long-term liabilities and deferred credits	2,008	2,000
Total long-term liabilities and deferred credits	31,034	32,674
Total Liabilities	37,964	38,495
Commitments and contingencies (Notes 9, 13, 17 and 18)		
Stockholders' Equity		
Class P Common Stock, $0.01 par value, 4,000,000,000 shares authorized, 2,247,681,626 and 2,267,391,527 shares, respectively, issued and outstanding	22	23
Additional paid-in capital	41,673	41,806
Accumulated deficit	(10,551)	(10,595)
Accumulated other comprehensive loss	(402)	(411)
Total Kinder Morgan, Inc.'s stockholders' equity	30,742	30,823
Noncontrolling interests	1,372	1,098
Total Stockholders' Equity	32,114	31,921
Total Liabilities and Stockholders' Equity	$ 70,078	$ 70,416

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2022	2021	2020
Cash Flows From Operating Activities			
Net income	$ 2,625	$ 1,850	$ 180
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,186	2,135	2,164
Deferred income taxes	692	355	345
Amortization of excess cost of equity investments	75	78	140
(Gain) loss on divestitures and impairments, net (Note 4)	(32)	1,624	1,932
Gain on sale of interest in equity investment (Note 3)	—	(206)	—
Earnings from equity investments	(803)	(591)	(780)
Distributions of equity investment earnings	725	720	633
Pension contributions net of noncash pension benefit expenses	(50)	(39)	(90)
Changes in components of working capital, net of the effects of acquisitions and dispositions			
Accounts receivable	(220)	(265)	88
Inventories	(183)	(202)	16
Other current assets	(51)	(109)	49
Accounts payable	161	387	(19)
Accrued interest, net of interest rate swaps	50	(17)	(51)
Accrued taxes	(5)	2	(93)
Other current liabilities	(10)	146	(81)
Rate reparations, refunds and other litigation reserve adjustments	(190)	(57)	40
Other, net	(3)	(103)	77
Net Cash Provided by Operating Activities	4,967	5,708	4,550
Cash Flows From Investing Activities			
Acquisitions of assets and investments, net of cash acquired (Note 3)	(487)	(1,547)	(16)
Capital expenditures	(1,621)	(1,281)	(1,707)
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	6	406	1,069
Contributions to investments	(229)	(38)	(386)
Distributions from equity investments in excess of cumulative earnings	156	163	154
Other, net	—	(8)	(25)
Net Cash Used in Investing Activities	(2,175)	(2,305)	(911)
Cash Flows From Financing Activities			
Issuances of debt	9,058	5,959	3,888
Payments of debt	(9,735)	(6,831)	(3,996)
Debt issue costs	(25)	(27)	(25)
Dividends (Note 11)	(2,504)	(2,443)	(2,362)
Repurchases of shares	(368)	—	(50)
Proceeds from sale of noncontrolling interests (Note 3)	557	—	—
Contributions from investment partner and noncontrolling interests	2	4	14
Distributions to investment partner	—	(82)	(79)
Distributions to noncontrolling interests	(116)	(20)	(15)
Other, net	(14)	(25)	(13)
Net Cash Used in Financing Activities	(3,145)	(3,465)	(2,638)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	(1)
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Deposits	(353)	(62)	1,000
Cash, Cash Equivalents and Restricted Deposits, beginning of period	1,147	1,209	209
Cash, Cash Equivalents and Restricted Deposits, end of period	$ 794	$ 1,147	$ 1,209

KINDER MORGAN, INC. AND SUBSIDIARIES (continued)
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2022	**2021**	**2020**
Cash and Cash Equivalents, beginning of period	$ 1,140	$ 1,184	$ 185
Restricted Deposits, beginning of period	7	25	24
Cash, Cash Equivalents and Restricted Deposits, beginning of period	1,147	1,209	209
Cash and Cash Equivalents, end of period	745	1,140	1,184
Restricted Deposits, end of period	49	7	25
Cash, Cash Equivalents and Restricted Deposits, end of period	794	1,147	1,209
Net (Decrease) Increase in Cash, Cash Equivalents and Restricted Deposits	$ (353)	$ (62)	$ 1,000
Noncash Investing and Financing Activities			
Increase in property, plant and equipment from both accruals and contractor retainage	$ 72	$ 74	
ROU assets and operating lease obligations recognized (Note 17)	22	59	$ 20
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,460	1,529	1,661
Cash paid during the period for income taxes, net	13	10	227

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions)

	Common stock							
	Issued shares	Par value	Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2019	2,265	$ 23	$ 41,745	$ (7,693)	$ (333)	$ 33,742	$ 344	$ 34,086
Repurchases of shares	(4)		(50)			(50)		(50)
Restricted shares	3		61			61		61
Net income				119		119	61	180
Dividends				(2,362)		(2,362)		(2,362)
Distributions						—	(15)	(15)
Contributions						—	11	11
Other						—	1	1
Other comprehensive loss					(74)	(74)		(74)
Balance at December 31, 2020	2,264	23	41,756	(9,936)	(407)	31,436	402	31,838
Restricted shares	3		50			50		50
Net income				1,784		1,784	66	1,850
Dividends				(2,443)		(2,443)		(2,443)
Distributions						—	(20)	(20)
Contributions						—	4	4
Reclassification of redeemable noncontrolling interest						—	646	646
Other comprehensive loss					(4)	(4)		(4)
Balance at December 31, 2021	2,267	23	41,806	(10,595)	(411)	30,823	1,098	31,921
Impact of adoption of ASU 2020-06 (Note 11)			(11)			(11)		(11)
Balance at January 1, 2022	2,267	23	41,795	(10,595)	(411)	30,812	1,098	31,910
Repurchases of shares	(21)	(1)	(367)			(368)		(368)
EP Trust I Preferred security conversions			1			1		1
Restricted shares	2		54			54		54
Net income				2,548		2,548	77	2,625
Dividends				(2,504)		(2,504)		(2,504)
Distributions						—	(116)	(116)
Contributions						—	2	2
Impact of change in ownership interest in subsidiary			190			190	311	501
Other comprehensive income					9	9		9
Balance at December 31, 2022	2,248	$ 22	$ 41,673	$ (10,551)	$ (402)	$ 30,742	$ 1,372	$ 32,114

The accompanying notes are an integral part of these consolidated financial statements.

1. General

We are one of the largest energy infrastructure companies in North America. Unless the context requires otherwise, references to "we," "us," "our," "the Company," or "KMI" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Our pipelines transport natural gas, refined petroleum products, renewable fuels, crude oil, condensate, CO_2 and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, renewable fuel feedstocks, chemicals, ethanol, metals and petroleum coke.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying consolidated financial statements have been prepared under the rules and regulations of the SEC. These rules and regulations conform to the accounting principles contained in the FASB's Accounting Standards Codification (ASC), the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including those related to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Deposits

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Amounts included in the restricted deposits in the accompanying consolidated financial statements represent a combination of restricted cash amounts required to be set aside by regulatory agencies to cover obligations for our captive insurance subsidiary, cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions and escrow deposits.

Allowance for Credit Losses

We evaluate our financial assets measured at amortized cost and off-balance sheet credit exposures for expected credit losses over the contractual term of the asset or exposure. We consider available information relevant to assessing the collectability of cash flows including the expected risk of credit loss even if that risk is remote. We measure expected credit losses on a collective (pool) basis when similar risk characteristics exist, and we reflect the expected credit losses on the amortized cost basis of the financial asset as of the reporting date.

Our financial instruments primarily consist of our accounts receivable from customers, notes receivable from affiliates and contingent liabilities such as proportional guarantees of debt obligations of an equity investee. We utilized historical analysis of credit losses experienced over the previous five years along with current conditions and reasonable and supportable forecasts of future conditions in our evaluation of collectability of our financial assets.

Our allowance for credit losses as of both December 31, 2022 and 2021 was $1 million and is included in "Other current assets" in our accompanying consolidated balance sheets.

Inventories

Our inventories consist of materials and supplies and products such as natural gas, NGL, crude oil, condensate, refined petroleum products and transmix. We report products inventory at the lower of weighted-average cost or net realizable value. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Property, Plant and Equipment, net

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for routine maintenance and repairs in the period incurred. The following table summarizes our significant policies related to our property, plant and equipment. The application of these policies can involve significant estimates.

Asset	Accounting Area	Policy
Straight-line assets	Depreciation rates	• Depreciable lives are based on estimated economic lives. This includes age, manufacturing specifications, technological advances, estimated production life of the oil or gas field served by the asset, contract terms for assets on leased or customer property and historical data concerning useful lives of similar assets.
	Gains and losses	• A gain or loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sale proceeds received or when held for sale, the market value of the asset. • A gain on an asset disposal is recognized in income in the period that the sale is closed. • A loss is recognized when the asset is sold or when classified as held for sale. • Gains and losses are recorded in operating costs, expenses and other.
Composite assets	Depreciation rates	• A single depreciation rate is applied to the total cost of a functional group of assets that have similar economic characteristics until the net book value of the composite group equals the salvage value. • Interstate natural gas FERC-regulated entities use the depreciation rates approved by the FERC. • A depreciation rate for other composite assets is based on estimated economic lives. This includes age, manufacturing specifications, technological advances, estimated production life of the oil or gas field served by the asset, contract terms for assets on leased or customer property and historical data concerning useful lives of similar assets.
	Gains and losses	• Gains and losses are credited or charged to accumulated depreciation, net of salvage and cost of removal. • Gains and losses on FERC-approved operating unit sales and land sales are recorded in operating costs, expenses and other.
Oil and gas producing activities(a)	Successful efforts method of accounting	• Costs that are incurred to acquire leasehold and subsequent development costs are capitalized. • Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. • Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. • The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. • Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.
	Enhanced recovery techniques	• In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. • The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. • When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. • Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs.

(a) Gains and losses associated with assets in our oil and gas producing activities have a similar treatment as with that associated with our straight-line assets.

Circumstances may develop which cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. The majority of our asset retirement obligations are associated with our CO_2 business where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors, but we also have obligations for certain gathering and long-haul pipelines and certain processing plants. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. The fair value estimates are primarily based on Level 3 inputs of the fair value hierarchy. The inputs include estimates and assumptions related to timing of settlement and retirement costs, which we base on historical retirement costs, future inflation rates and credit-adjusted risk-free interest rates. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities are accreted to reflect the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service. Our estimates of retirement costs could change as a result of changes in cost estimates and/or timing of the obligation.

The following table summarizes changes in the asset retirement obligations included in our accompanying consolidated balance sheets:

	December 31,	
	2022	**2021**
	(In millions)	
Balance at beginning of period	$ 196	$ 215
Accretion expense	12	7
New obligations	2	6
Settlements	(6)	(8)
Revisions to previous estimates	—	(24)
Balance at end of period(a)	$ 204	$ 196

(a) Balances at December 31, 2022 and 2021 include $3 million and $4 million, respectively, included within "Other current liabilities" on our accompanying consolidated balance sheets.

For certain assets, we currently cannot reasonably estimate the fair value of the asset retirement obligations because the associated assets have indeterminate lives. These assets include certain pipelines, processing plants and distribution facilities, and liquids and bulk terminal facilities. Based on the widespread use of hydrocarbons domestically and for international export, management expects supply and demand to exist for the foreseeable future. Therefore, the remaining useful lives of these assets is indeterminate due to prolonged expected demand. Additionally, these assets could also benefit from potential future conversion opportunities. For example, certain assets could be converted to transport, handle or store products other than traditional hydrocarbons. Under our integrity program, individual asset parts are replaced regularly. Although some of the individual asset parts may be replaced, the assets themselves may remain intact indefinitely. For these assets, an asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

Long-lived Asset Impairments

We evaluate long-lived assets including leases and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable.

In addition to our annual goodwill impairment test discussed further below, to the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments using a two-step approach. To determine if a long-lived asset is recoverable, we compare the asset's estimated undiscounted cash flows to its carrying value (step 1). Because the impairment test for long-lived assets held in use is based on estimated undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. If the carrying value of a long-lived asset or asset group is in excess of estimated undiscounted cash flows, we typically use discounted cash flow analyses to calculate the fair value of the long-lived asset to determine if an impairment is required and the amount of the impairment losses to be recognized (step 2).

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on estimated future oil and gas production volumes.

Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on estimated future oil and gas production volumes. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Refer to Note 4 for further information.

Equity Method of Accounting and Basis Differences

We use the equity method of accounting for investments which we do not control, but for which we have the ability to exercise significant influence. The carrying values of these investments are impacted by our share of investee income or loss, distributions, amortization or accretion of basis differences and other-than-temporary impairments.

The difference between the carrying value of an investment and our share of the investment's underlying equity in net assets is referred to as a basis difference. If the basis difference is assigned to depreciable or amortizable assets and liabilities, the basis difference is amortized or accreted as part of our share of investee earnings. To the extent that the basis difference relates to goodwill, referred to as equity method goodwill, the amount is not amortized.

We evaluate our equity method investments for other-than-temporary impairment. When an other-than-temporary impairment is recognized the loss is recorded as a reduction in equity earnings.

Goodwill

Goodwill is the cost of an acquisition of a business in excess of the fair value of acquired assets and liabilities and is recorded as an asset on our balance sheet. Goodwill is not subject to amortization but must be tested for impairment at least annually and in interim periods if indicators of impairment exist. This test requires us to assign goodwill to an appropriate reporting unit and compare the fair value of a reporting unit to its carrying value. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value an impairment is measured and recorded at the amount by which the reporting unit's carrying value exceeds its fair value.

We evaluate goodwill for impairment on May 31 of each year, or more frequently to the extent events occur or conditions change between annual tests that would indicate a risk of possible impairment at the interim period. For purposes of our May 31, 2022 evaluation, we grouped our businesses into seven reporting units as follows: (i) Natural Gas Pipelines Regulated; (ii) Natural Gas Pipelines Non-Regulated; (iii) CO_2; (iv) Products Pipelines (excluding associated terminals); (v) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (vi) Terminals; and (vii) Energy Transition Ventures. Generally, the evaluation of goodwill for impairment involves a quantitative test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

Refer to Note 8 for further information.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts and other relationships and agreements.

Our intangible assets primarily relate to customer contracts or other relationships for the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline, and other refined petroleum products, petroleum coke, metals and ores, the gathering of natural gas and the production and supply of RNG. We determined the values of these intangible assets by first, estimating the revenues derived from a customer contract or relationship (offset by the cost and expenses of supporting assets to fulfill the contract), and second, discounting the revenues at a risk adjusted discount rate.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. The life of each intangible asset is based either on the life of the corresponding customer contract or agreement or, in the case of a customer relationship intangible (the life of which was determined by an analysis of all available data on that business relationship), the length of time used in the discounted cash flow analysis to determine the value of the customer relationship. Among the factors we weigh, depending on the nature of the asset, are the effects of obsolescence, new technology, and competition.

The following tables summarize our other intangible assets as of December 31, 2022 and 2021 and our amortization expense for the years ended December 31, 2022, 2021 and 2020:

	Weighted Average Amortization Period (years)	December 31, 2022	December 31, 2021
		(In millions)	
Gross	11.2	$ 3,382	$ 3,036
Accumulated amortization		(1,573)	(1,358)
Net carrying amount		$ 1,809	$ 1,678

	December 31, 2022	2021	2020
		(In millions)	
Amortization expense	$ 253	$ 237	$ 212

Our estimated amortization expense for our intangible assets for each of the next five fiscal years is:

	2023	2024	2025	2026	2027
			(In millions)		
Estimated amortization expenses	$ 201	$ 175	$ 170	$ 168	$ 167

Revenue Recognition

The majority of our revenues are accounted for under Topic 606, *Revenue from Contracts with Customers*; however, to a limited extent, some revenues are accounted for under other guidance such as Topic 842, *Leases* or Topic 815, *Derivatives and Hedging Activities*.

Revenue from Contracts with Customers

We review our contracts with customers using the following steps to recognize revenue based on the transfer of goods or services to customers and in amounts that reflect the consideration the company expects to receive for those goods or services. The steps include: (i) identify the contract; (ii) identify the performance obligations of the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and then (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management judgment and an analysis of the contract's material terms and conditions.

Our customer sales contracts primarily include sales of natural gas, NGL, crude oil, CO_2 and transmix, as described below. Generally, for the majority of these contracts (i) each unit (Bcf, gallon, barrel, etc.) of commodity is a separate performance obligation, as our promise is to sell multiple distinct units of commodity at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity's standalone selling price and recognized as revenue upon delivery of the commodity, which is the point in time when the customer obtains control of the commodity and our performance obligation is satisfied.

Our customer services contracts are primarily for transportation service, storage service, gathering and processing service, and terminaling, as described below. Generally, for the majority of these contracts (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- *Contracts without Makeup Rights.* If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at the beginning of each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of service are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as "breakage"), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service (e.g., reservation) continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

- *Contracts with Makeup Rights.* If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at the beginning of each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any non-refundable consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition, and our right to invoice the customer is conditioned on something other than the passage of time. Our contract assets are substantially related to breakage revenue associated with our firm service contracts with minimum volume commitment payment obligations and contracts where we apply revenue levelization (i.e., contracts with fixed rates per volume that increase over the life of the contract for which we record revenue ratably per unit over the life of the contract based on our performance obligations that are generally unchanged over the life of the contract). Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts; (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires); and (iii) contracts with fixed rates per volume that decrease over the life of the contract where we apply revenue levelization for amounts received for our future performance obligations. We reassess amounts recorded as contract assets or liabilities upon contract modification.

Refer to Note 15 for further information.

Cost of Sales

Cost of sales primarily includes the cost to purchase energy commodities sold, including natural gas, crude oil, NGL and other refined petroleum products, adjusted for the effects of our energy commodity hedging activities, as applicable. Costs of our crude oil, gas and CO_2 producing activities, such as those in our CO_2 business segment, are not accounted for as costs of sales.

Operations and Maintenance

Operations and maintenance includes costs of services and is primarily comprised of (i) operational labor costs and (ii) operations, maintenance and asset integrity, regulatory and environmental costs. Costs associated with our crude oil, gas and CO_2 producing activities included within operations and maintenance totaled $367 million, $180 million and $319 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required to obtain rights-of-way, regulatory approvals or permitting as part of the construction of facilities we use in our business operations. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our accrual of these environmental liabilities coincides with either our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims we may have against others. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable.

Leases

We lease property including corporate and field offices and facilities, vehicles, heavy work equipment including rail cars and large trucks, tanks, office equipment and land. Our leases have remaining lease terms of one to 48 years, some of which have options to extend or terminate the lease. We determine if an arrangement is a lease at inception or upon modification. For purposes of calculating operating lease liabilities, lease terms may be deemed to include options to extend or terminate the lease when it is reasonably certain that we will exercise that option.

Our operating ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. Leases with variable rate adjustments, such as Consumer Price Index (CPI) adjustments, are reflected based on contractual lease payments as outlined within the lease agreement and not adjusted for any CPI increases or decreases. Because most of our leases do not provide an explicit rate of return, we use our incremental secured borrowing rate based on lease term information available at the commencement date of the lease in determining the present value of lease payments. We have real estate lease agreements with lease and non-lease components, which are accounted for separately. For certain equipment leases, such as copiers and vehicles, we account for the leases under a portfolio method. Leases that were grandfathered under various portions of Topic 842, such as land easements, are reassessed when the agreements are modified.

Refer to Note 17 for further information.

Share-based Compensation

We recognize compensation expense ratably over the vesting period of the restricted stock award based on the grant-date fair value, which is determined based on the market price of our Class P common stock on the grant date, less estimated forfeitures. Forfeiture rates are estimated based on historical forfeitures under our restricted stock award plans. Upon vesting, the restricted stock award will be paid in shares of our Class P common stock.

Pensions and Other Postretirement Benefits

We recognize the differences between the fair value of each of our and our consolidated subsidiaries' pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheets. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—net of income taxes in "Accumulated other comprehensive loss," with the proportionate share associated with less than wholly owned consolidated subsidiaries allocated and included within "Noncontrolling interests," or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense.

Deferred Financing Costs

We capitalize financing costs incurred with new borrowings and amortize the costs over the contractual term of the related obligations.

Redeemable Noncontrolling Interest

Through December 14, 2021, we had a redeemable noncontrolling interest which represented the interest in one of our consolidated subsidiaries, ELC, not owned by us, and which in certain limited circumstances, the partner had the right to relinquish its interest in the subsidiary and redeem its cumulative contributions, net of distributions it had received through date of the amended operating agreement. Distributions paid to EIG prior to that date were recorded as a reduction to the redeemable noncontrolling interest balance and included in "Distributions to investment partner" in our accompanying consolidated statements of cash flows. On December 14, 2021, the ownership agreement was modified such that EIG's interest was no longer contingently redeemable, and the balance was reclassified to "Noncontrolling Interests." Net income attributable to redeemable noncontrolling interest was $58 million and $54 million for the years ended December 31, 2021 and 2020, respectively, and is included in "Net Income Attributable to Noncontrolling Interests" in our accompanying consolidated statements of income.

Noncontrolling Interests

Noncontrolling interests represents the interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated statements of income, the noncontrolling interest in the net income of our less than wholly owned consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net Income

Attributable to Noncontrolling Interests." In our accompanying consolidated balance sheets, noncontrolling interests is presented separately as "Noncontrolling interests" within "Stockholders' Equity."

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are enacted. We do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective tax rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance when it is more-likely-than-not that all, or a portion, of a deferred tax asset will not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments, including KMI's investment in its wholly-owned subsidiary, KMP.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of commodities including crude oil, natural gas, and NGL. In addition, we enter into interest rate swap agreements for the purpose of managing our interest rate exposure associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk associated with certain debt obligations. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. For certain physical forward commodity derivatives contracts, we apply the normal purchase/normal sale exception, whereby the revenues and expenses associated with such transactions are recognized during the period when the commodities are physically delivered or received.

For qualifying accounting hedges, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness. When we designate a derivative contract as a cash flow accounting hedge, the entire change in fair value of the derivative that is included in the assessment of hedge effectiveness is deferred in "Accumulated other comprehensive loss" and reclassified into earnings in the period in which the hedged item affects earnings. When we designate a derivative contract as a fair value accounting hedge, the change in fair value of the hedged item is recorded as an adjustment to the carrying value of the hedged item and recognized currently in earnings in the same line item that the change in fair value of the derivative is recognized currently in earnings. Therefore, any difference between the changes in fair values of the item being hedged and the derivative contract results in a gain or loss from the hedging relationship recognized currently in earnings.

For derivative instruments that are not designated as accounting hedges, or for which we have not elected the normal purchase/normal sales exception, changes in fair value are recognized currently in earnings.

Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. We assign each fair value measurement to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. Recognized valuation techniques utilize inputs such as contractual prices, quoted market prices or rates, and discount factors. These inputs may be either readily observable or corroborated by market data.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or returned to customers through the ratemaking process. In instances where we receive recovery in tariff rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount. We include the amounts of our regulatory assets and liabilities within “Other current assets,” “Deferred charges and other assets,” “Other current liabilities” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheets.

The following table summarizes our regulatory asset and liability balances as of December 31, 2022 and 2021:

	December 31,	
	2022	2021
	(In millions)	
Current regulatory assets	$ 73	$ 66
Non-current regulatory assets	183	220
Total regulatory assets(a)	$ 256	$ 286
Current regulatory liabilities	$ 50	$ 32
Non-current regulatory liabilities	175	163
Total regulatory liabilities(b)	$ 225	$ 195

(a) Regulatory assets as of December 31, 2022 include (i) $110 million of unamortized losses on disposal of assets; (ii) $45 million income tax gross up on equity AFUDC; and (iii) $101 million of other assets, including amounts related to fuel tracker arrangements. Approximately $143 million of the regulatory assets, with a weighted average remaining recovery period of 10 years, are recoverable without earning a return, including the income tax gross up on equity AFUDC for which there is an offsetting deferred income tax balance for FERC rate base purposes; therefore, it does not earn a return.

(b) Regulatory liabilities as of December 31, 2022 are comprised of customer prepayments to be credited to shippers or other over-collections that are expected to be returned to shippers or netted against under-collections over time. Approximately $110 million of the $175 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 15 years, while the remaining $65 million is not subject to a defined period.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P common stock and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be restricted stock or restricted stock units issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of net income available to shareholders of Class P common stock and participating securities:

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts)		
Net Income Available to Stockholders	$ 2,548	$ 1,784	$ 119
Participating securities:			
Less: Net Income Allocated to Restricted stock awards(a)	(13)	(14)	(13)
Net Income Allocated to Class P Stockholders	$ 2,535	$ 1,770	$ 106
Basic Weighted Average Shares Outstanding	2,258	2,266	2,263
Basic Earnings Per Share	$ 1.12	$ 0.78	$ 0.05

(a) As of December 31, 2022, there were approximately 13 million restricted stock awards outstanding.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share. As we have no other common stock equivalents, our diluted earnings per share are the same as our basic earnings per share for all periods presented.

	Year Ended December 31,		
	2022	2021	2020
	(In millions on a weighted average basis)		
Unvested restricted stock awards	13	13	13
Convertible trust preferred securities	3	3	3

3. Acquisitions and Divestitures

Business Combinations

For acquired businesses, we recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition with any excess purchase price over the fair value of net assets acquired recorded to goodwill. Determining the fair value of these items requires management's judgment and the utilization of an independent valuation specialist, if applicable, and involves the use of significant estimates and assumptions.

As of December 31, 2022, our allocation of the purchase price for significant acquisitions completed during the years ended December 31, 2022 and 2021 are detailed below:

				Assignment of Purchase Price					
Ref	Date	Acquisition	Purchase price	Current assets	Property, plant & equipment	Other long-term assets	Current liabilities	Long-term liabilities	Resulting goodwill
						(In millions)			
(1)	8/22	North American Natural Resources	$ 132	$ 2	$ 5	$ 64	$ —	$ —	$ 61
(2)	7/22	Mas Ranger, LLC	358	9	31	320	(2)	—	—
(3)	8/21	Kinetrex	318	18	49	272	(6)	(68)	53
(4)	7/21	Stagecoach	1,258	53	1,187	24	(6)	—	—

(1) North American Natural Resources Acquisition

On August 11, 2022, we completed the acquisition of seven landfill assets with the purchase of North American Natural Resources, Inc. and, its sister companies, North American Biofuels, LLC and North American-Central, LLC (NANR) consisting of GTE facilities in Michigan and Kentucky for $132 million, including purchase price adjustments for working capital. Other long-term assets within the preliminary purchase price allocation consists of intangibles related to gas rights and customer contracts with a weighted average amortization period of approximately 13 years. The goodwill associated with this acquisition is tax deductible. The acquired assets align with our strategy to invest in low-carbon energy and are included as part of our new Energy Transition Ventures group within our CO_2 business segment.

(2) Mas Ranger Acquisition

On July 19, 2022, we completed an acquisition of three landfill assets with the purchase of Mas Ranger, LLC and its subsidiaries from Mas CanAm, LLC, comprising an RNG facility in Arlington, Texas and medium Btu facilities in Shreveport, Louisiana and Victoria, Texas for $358 million including preliminary purchase price adjustments for working capital. Other long-term assets within the preliminary purchase price allocation reflects an intangible related to a customer contract with an amortization period of approximately 17 years. The acquired assets align with our strategy to invest in low-carbon energy and are included as part of our new Energy Transition Ventures group within our CO_2 business segment.

(3) Kinetrex Acquisition

On August 20, 2021, we completed the acquisition of Indianapolis-based Kinetrex from an affiliate of Parallel49 Equity for $318 million, including purchase price adjustments for working capital. Deferred charges and other within the purchase price allocation includes $63 million related to an equity investment and $199 million related to a customer relationship with an amortization period of approximately 10 years. Kinetrex is a supplier of LNG in the Midwest and a producer and supplier of

RNG under long-term contracts to transportation service providers. Kinetrex has a 50% interest in the largest RNG facility in Indiana, and we commenced construction on three additional landfill-based RNG facilities in September 2021. The acquired assets align with our strategy to invest in low-carbon energy and are included as part of our new Energy Transition Ventures group within our CO_2 business segment.

(4) Stagecoach Acquisition

On July 9, 2021 and November 24, 2021, we completed the acquisitions of Stagecoach and its subsidiaries, a natural gas pipeline and storage joint venture between Consolidated Edison, Inc. and Crestwood Equity Partners, LP, for approximately $1,258 million, including a purchase price adjustment for working capital. Deferred charges and other within the purchase price allocation relates to customer contracts with a weighted average amortization period of less than 2 years. The determination of fair value utilized valuation methodologies including discounted cash flows and the cost approach. The significant assumptions made in performing these valuations include a discount rate of approximately 12%, future revenues and replacement costs. To compute estimated future cash flows for Stagecoach, transportation and storage revenue forecasts were developed based on projected demand and future rates for services in the Northeast market areas.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to the above acquisitions as if they had occurred as of January 1, 2021 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Divestitures

Sale of Interest in ELC

On September 26, 2022, we completed the sale of a 25.5% ownership interest in ELC. We received net proceeds of $557 million which were used to reduce short-term borrowings. As we continue to have a controlling financial interest in ELC, we recorded an increase of $190 million to “Additional paid in capital” for the impact of the change in our ownership interest in ELC, which is reflected on our accompanying consolidated statement of stockholders’ equity for the year ended December 31, 2022. We continue to own a 25.5% interest in and operate ELC.

We continue to consolidate ELC. We have determined that ELC is a variable interest entity and Southern Liquefaction Company, LLC (SLC), which is indirectly controlled by us, is the primary beneficiary because it has the ability to direct the activities that most significantly impact ELC’s economic performance and the right to receive benefits and the obligation to absorb losses. In addition to being the operator of ELC, the evaluation of ELC as a variable interest entity and SLC as the primary beneficiary included consideration of the following: (i) a liquefaction service agreement between ELC and its customer was designed for recovery by ELC of actual costs for operating and maintaining ELC’s facilities, which reduces the risk for all equity owners to absorb losses resulting from cost variability; and (ii) substantially all ELC’s activities involve KMI subsidiaries under common control that provide services for and benefit from the operations of ELC.

The following table shows the carrying amount and classification of ELC’s assets and liabilities in our consolidated balance sheet:

	December 31, 2022 (In millions)	
Assets		
Current assets	$	34
Property, plant and equipment, net		1,197
Deferred charges and other assets		6
Liabilities		
Current liabilities	$	15
Other long-term liabilities and deferred credits		5

We receive distributions from ELC, indirectly, through our interest in SLC, but otherwise, the assets of ELC cannot be used to settle our obligations. ELC’s creditors have no recourse against our general credit and the obligations of ELC may only be settled using the assets of ELC. ELC does not guarantee our debt or other similar commitments.

Sale of an Interest in NGPL Holdings LLC

On March 8, 2021, we and Brookfield Infrastructure Partners L.P. (Brookfield) completed the sale of a combined 25% interest in our joint venture, NGPL Holdings LLC (NGPL Holdings), to a fund controlled by ArcLight Capital Partners, LLC (ArcLight). We received net proceeds of $412 million for our proportionate share of the interests sold, which included the transfer of $125 million of our $500 million related party promissory note receivable from NGPL Holdings to ArcLight with quarterly interest payments at 6.75%. We recognized a pre-tax gain of $206 million for our proportionate share, which is included within “Other, net” in our accompanying consolidated statement of income for the year ended December 31, 2021. We and Brookfield now each hold a 37.5% interest in NGPL Holdings.

4. Gains and Losses on Divestitures, Impairments and Other Write-downs

During the years ended December 31, 2022, 2021, and 2020, we recorded net pre-tax (gains) losses of $(32) million, $1,535 million and $1,922 million, respectively, reflecting net (gains) losses on divestitures, impairments and other write downs as detailed further below. The year ended December 31, 2021 amount primarily includes pre-tax long-lived asset impairments of $1,634 million. The year ended December 31, 2020 amount primarily includes pre-tax goodwill and long-lived asset impairment losses of $1,600 million and $376 million, respectively.

We recognized the following non-cash pre-tax (gains) losses on divestitures, impairments or other write-downs on assets and equity investments during the years ended December 31, 2022, 2021, and 2020:

	Year Ended December 31,		
	2022	**2021**	**2020**
		(In millions)	
Natural Gas Pipelines			
Impairments of long-lived assets(a)	$ —	$ 1,600	$ —
Impairment of goodwill(b)	—	—	1,000
Gain on sale of interest in NGPL Holdings(c)	—	(206)	—
Loss on write-down of related party note receivable(d)	—	117	—
(Gains) losses on divestitures of long-lived assets	(10)	(1)	10
Products Pipelines			
Impairments of long-lived assets	—	—	21
Gain on divestiture of long-lived asset	(12)	—	—
Terminals			
Impairments of long-lived assets	—	34	5
(Gains) losses on divestitures of long-lived assets(e)	(9)	2	(54)
Gain on sale of equity investment interests	—	—	(10)
CO_2			
Impairment of goodwill(b)	—	—	600
Impairments of long-lived assets(f)	—	—	350
Gains on divestitures of long-lived assets	(1)	(8)	—
Other gains on divestitures of long-lived assets	—	(3)	—
Pre-tax (gains) losses on divestitures, impairments and other write-downs, net	$ (32)	$ 1,535	$ 1,922

(a) 2021 amount represents non-cash impairments associated with our South Texas gathering and processing assets.
(b) 2020 amount represent non-cash goodwill impairments associated with our Natural Gas Pipelines Non-Regulated and CO_2 reporting units (see “*—Impairments—Goodwill*” below).
(c) See Note 3.
(d) See “*—Investment in Ruby*” below for a further discussion.
(e) 2020 amount includes a $55 million gain related to the sale of our Staten Island terminal.
(f) 2020 amount represents a non-cash impairment of oil and gas properties.

Impairments

Long-lived Assets

During the second quarter of 2021, we evaluated our South Texas gathering and processing assets within our Natural Gas Pipeline business segment for impairment, which was driven by lower expectations regarding the volumes and rates associated with the re-contracting of contracts expiring through 2024. To compute the estimated undiscounted future cash flows we used the forecast of expected revenues adjusted for upcoming contract expirations. This analysis indicated that our South Texas gathering and processing assets failed step one. In step two, we utilized an income approach to estimate fair value and compared it to the carrying value. The significant assumptions made in calculating fair value include estimates of future cash flows and discount rates. We applied an approximate 8.5% discount rate, a Level 3 input, which we believed represented the estimated weighted average cost of capital of a theoretical market participant. As a result of our evaluation, we recognized a non-cash, long-lived asset impairment of $1,600 million during the year ended December 31, 2021.

During the first half of 2020, the energy production and demand factors related to COVID-19 and the sharp decline in commodity prices represented a triggering event that required us to perform impairment testing on certain businesses that are sensitive to commodity prices. As a result, we performed an impairment analysis of long-lived assets within our CO_2 business segment which resulted in a non-cash impairment of long-lived assets within our CO_2 business segment shown in the above table during the year ended December 31, 2020.

As of March 31, 2020, for our CO_2 assets, the computation of estimated undiscounted future cash flows included the following:

- To compute estimated future cash flows for our oil and gas producing properties, we used our reserve engineer specialists to estimate future oil and gas production volumes. These estimates of future oil and gas production volumes are based upon historical performance along with adjustments for expected crude oil and natural gas field development. In calculating future cash flows, management utilized estimates of commodity prices based on a March 31, 2020 NYMEX forward curve adjusted for the impact of our existing sales contracts to determine the applicable net crude oil and NGL pricing for each property. Operating expenses were determined based on estimated fixed and variable field production requirements, and capital expenditures were based on economically viable development projects.

- To compute estimated future cash flows for our CO_2 source and transportation assets, throughput and production volume forecasts were developed based on projected demand for our CO_2 services based upon management's projections of the availability of CO_2 supply and the future demand for CO_2 for use in enhanced oil recovery projects. The CO_2 pricing assumption was a function of the March 31, 2020 NYMEX forward curve adjusted for the impact of existing sales contracts to determine the applicable net CO_2 pricing. Operating expenses were determined based on estimated fixed and variable field production requirements, and capital expenditures were based on economically viable development projects.

For certain oil and gas properties that failed the first step, we used a discounted cash flow analysis to estimate fair value. We applied a 10.5% discount rate, which we believe represented the estimated weighted average cost of capital of a theoretical market participant. Based on step two of our long-lived assets impairment test, we recognized $350 million of impairments on those oil and gas producing properties where the total carrying value exceeded its total estimated fair market value as of March 31, 2020.

Goodwill

The fair value estimates used in our goodwill impairment test are primarily based on Level 3 inputs of the fair value hierarchy. The inputs include valuation estimates using market and income approach valuation methodologies, which include assumptions primarily involving management's significant judgments and estimates with respect to market multiples, comparable sales transactions, weighted average costs of capital, general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding future cash flows based on production growth rate assumptions, terminal values and discount rates. Prior to 2022, we used primarily a market approach and, in some instances where deemed necessary, also used discounted cash flow analyses to determine the fair value of our assets. We used discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular reporting unit.

During the first quarter of 2020, we conducted interim impairment tests of goodwill for our CO_2 and Natural Gas Pipelines Non-Regulated reporting units, and during the second quarter 2020, we conducted our annual impairment test of goodwill for all of our reporting units which resulted in non-cash impairments of goodwill within our CO_2 and Natural Gas Pipelines business segments during the year ended December 31, 2020 as shown in the table above.

- Our May 31, 2020 goodwill impairment tests of the Products Pipelines, Products Pipelines Terminals, Natural Gas Pipelines Regulated and CO_2 reporting units indicated that their fair values exceeded their carrying values. The results of our impairment analyses for our Products Pipelines, Terminals and CO_2 reporting units, determined that each of the three reporting unit's fair value was in excess of carrying value by less than 10%. For the Products Pipelines and Terminals reporting units, we used the market approach with assumptions similar to those described below for the Natural Gas Pipelines Non-Regulated reporting unit. For our May 31, 2020 goodwill impairment test of the CO_2 reporting unit we used the income approach with assumptions similar to those used for its March 31, 2020 goodwill impairment test.

- In regards to our Natural Gas Pipelines Non-Regulated reporting unit, while no impairment was required as of March 31, 2020, it experienced a sharp decline in customer demand for its services during the second quarter of 2020. This represented a timing lag from the initial economic decline impacts resulting from the severe downturn in the upstream energy industry, including our CO_2 business, whereby oil and gas producing companies accelerated their shut down of wells and reduced production during the second quarter which consequently adversely impacted the demand for our midstream services. In addition, continued diminished (i) current and expected future commodity pricing and (ii) peer group market capitalization values provided further indicators that an impairment of goodwill had occurred for this reporting unit during the second quarter.

  Our May 31, 2020 goodwill impairment test for the Natural Gas Pipelines Non-Regulated reporting unit utilized a weighted average of a market approach (25%) and income approach (75%) to estimate its fair value. We gave higher weighting to the income approach as we believe it was more representative of the value that would be received from a market participant.

  The market approach was based on enterprise value (EV) to estimated 2020 EBITDA multiples for a selected number of peer group midstream companies with comparable operations and economic characteristics. We estimated the median EV to EBITDA multiple to be approximately 10x without consideration of any control premium. The income approach we used to determine fair value included an analysis of estimated discounted cash flows based on 6.5 years of projections and application of an exit multiple based on management's expectations of a discount rate and exit multiple that would be applied by a theoretical market participant and for market transactions of comparable assets. We applied an approximate 8% discount rate to the undiscounted cash flow amounts which represents our estimate of the weighted average cost of capital of a theoretical market participant. The discounted cash flows included various assumptions on forecasted commodity throughput volumes and contract prices for each underlying asset within the reporting unit. The fair value based on a weighting of the market and income approaches resulted in an implied EV to 2020 EBITDA multiple valuation of approximately 11x. Management believes this is a reasonable estimate of fair value based on comparable sales transactions and the fact that it implies a reasonable control premium.

  The results of the Natural Gas Pipelines Non-Regulated reporting unit goodwill impairment analysis was a partial impairment of goodwill of approximately $1,000 million as of May 31, 2020.

- For our March 31, 2020 interim goodwill impairment test of the CO_2 reporting unit, we applied an income approach to evaluate its fair value based on the present value of its cash flows that it is expected to generate in the future. Due to the uncertainty and volatility in market conditions within its peer group as of the test date, we did not incorporate the market approach to estimate fair value as of March 31, 2020.

  In determining the fair value for our CO_2 reporting unit, we applied a 9.25% discount rate to the undiscounted cash flow amounts computed in the long-lived asset impairment analyses described above. The discount rate we used represents our estimate of the weighted average cost of capital of a theoretical market participant. The result of our goodwill analysis was a partial impairment of goodwill in our CO_2 reporting unit of approximately $600 million as of March 31, 2020.

The fair value estimates used in the long-lived asset and goodwill tests were primarily based on Level 3 inputs of the fair value hierarchy.

Economic disruptions resulting from events such as COVID-19, conditions in the business environment generally, such as sustained low crude oil demand and continued low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our pipelines, terminals and other assets, which will have an adverse effect on the demand for services provided by our four business segments. Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

As conditions warrant, we routinely evaluate our assets for potential triggering events that could impact the fair value of certain assets or our ability to recover the carrying value of long-lived assets. Such assets include accounts receivable, equity investments, goodwill, other intangibles and property plant and equipment, including oil and gas properties and in-process construction. Depending on the nature of the asset, these evaluations require the use of significant judgments including but not limited to judgments related to customer credit worthiness, future volume expectations, current and future commodity prices, discount rates, regulatory environment, as well as general economic conditions and the related demand for products handled or transported by our assets. Because certain of our assets have been written down to fair value, or its fair value is close to carrying value, any deterioration in fair value could result in further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to not be recoverable.

For additional information regarding changes in our goodwill, see Note 8.

Investment in Ruby

During the first quarter of 2021, we recognized a pre-tax charge of $117 million related to a write-down of our subordinated note receivable from our equity investee, Ruby, which is included within "Earnings from equity investments" in our accompanying consolidated statement of income for the year ended December 31, 2021. The write-down was driven by the impairment recognized by Ruby of its assets.

Ruby Chapter 11 Bankruptcy Filing

The balance of Ruby Pipeline, L.L.C.'s 2022 unsecured notes matured on April 1, 2022 in the principal amount of $475 million. Although Ruby had sufficient liquidity to operate its business, it lacked sufficient liquidity to satisfy its obligations under the 2022 unsecured notes on the maturity date of April 1, 2022. Accordingly, on March 31, 2022, Ruby filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. Ruby, as the debtor, continued to operate in the ordinary course as a debtor in possession under the jurisdiction of the United States Bankruptcy Court. We fully impaired our equity investment in Ruby in the fourth quarter of 2019 and fully impaired our investment in Ruby's subordinated notes in the first quarter of 2021. We had no amounts included in our "Investments" on our accompanying consolidated balance sheets associated with Ruby as of December 31, 2022 or 2021.

On January 13, 2023, the bankruptcy court confirmed a plan of reorganization satisfactory to all interested parties regarding Ruby, which involved payment of Ruby's outstanding senior notes with the proceeds from the sale of Ruby to Tallgrass, a settlement by KMI and Pembina of certain potential causes of action relating to the bankruptcy, and cash on hand. Our payment to the bankruptcy estate, net of payments it received in respect of a long-term subordinated note receivable from Ruby, was approximately $28.5 million which was accrued for as of December 31, 2022 and included within "Other, net" in our accompanying consolidated statement of income for the year ended December 31, 2022. Consummation of the settlement and the sale of Ruby to Tallgrass occurred on January 13, 2023.

5. Income Taxes

The components of "Income Before Income Taxes" are as follows:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
U.S.	$ 3,318	$ 2,217	$ 663
Foreign	17	2	(2)
Total Income Before Income Taxes	$ 3,335	$ 2,219	$ 661

Components of the income tax provision applicable for federal, foreign and state taxes are as follows:

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Current tax expense (benefit)			
Federal	$ —	$ —	$ (20)
State	14	11	9
Foreign	4	3	147
Total	18	14	136
Deferred tax expense (benefit)			
Federal	642	334	440
State	50	21	49
Foreign	—	—	(144)
Total	692	355	345
Total tax provision	$ 710	$ 369	$ 481

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows:

	Year Ended December 31,					
	2022		2021		2020	
	(In millions, except percentages)					
Federal income tax	$ 700	21.0 %	$ 466	21.0 %	$ 139	21.0 %
Increase (decrease) as a result of:						
Net effects of noncontrolling interests	(16)	(0.5)%	(14)	(0.6)%	(13)	(2.0)%
State income tax, net of federal benefit	69	2.0 %	50	2.2 %	52	7.9 %
Dividend received deduction	(36)	(1.1)%	(46)	(2.1)%	(27)	(4.1)%
Release of valuation allowance	—	— %	(38)	(1.7)%	—	— %
Nondeductible goodwill	—	— %	—	— %	336	50.8 %
General business credit	—	— %	(36)	(1.6)%	—	— %
Federal refunds	—	— %	—	— %	(20)	(3.0)%
Other	(7)	(0.2)%	(13)	(0.6)%	14	2.2 %
Total	$ 710	21.2 %	$ 369	16.6 %	$ 481	72.8 %

Deferred tax assets and liabilities result from the following:

	December 31,	
	2022	2021
	(In millions)	
Deferred tax assets		
Employee benefits	$ 116	$ 154
Net operating loss carryforwards	2,007	1,476
Tax credit carryforwards	303	301
Interest expense limitation	82	—
Other	192	229
Valuation allowances	(79)	(93)
Total deferred tax assets	2,621	2,067
Deferred tax liabilities		
Property, plant and equipment	163	166
Investments	3,056	1,769
Other	25	17
Total deferred tax liabilities	3,244	1,952
Net deferred tax (liability)/asset	$ (623)	$ 115

Deferred Tax Assets and Valuation Allowances

A reconciliation of our valuation allowances for the year ended December 31, 2022 is as follows:

		Year Ended December 31, 2022
		(In millions)
Balance at beginning of period	$	93
Statute expirations for federal and state NOL and foreign tax credits		(16)
Currency fluctuation		2
Balance at end of period	$	79

The following table provides details related to our deferred tax assets and valuation allowances as of December 31, 2022:

	Unused Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
		(In millions)		
Net Operating Loss				
U.S. federal net operating loss	$ 5,005	$ 1,051	$ —	Indefinite
U.S. federal net operating loss	3,209	674	—	2029 - 2037
State losses	5,034	254	(47)	2023 - 2042
Foreign losses	83	28	(28)	Indefinite
Tax Credits				
General business credits	299	299	—	2036 - 2042
Foreign tax credits	4	4	(4)	2023 - 2027

Use of a portion of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations. If certain substantial changes in our ownership occur, there would be an annual limitation on the amount of carryforwards that could be utilized.

Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

A reconciliation of our gross unrecognized tax benefit excluding interest and penalties is as follows:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Balance at beginning of period	$ 21	$ 18	$ 16
Reductions based on statute expirations	(5)	—	—
Additions to state reserves for prior years	7	3	2
Balance at end of period	$ 23	$ 21	$ 18
Amounts which, if recognized, would affect the effective tax rate	$ 23		

In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will increase by $4 million during the next year, primarily due to additions for state filing positions taken in prior years, offset by releases from statute expirations.

The following table summarizes information of our open tax years:

Jurisdiction	Open Tax Year
U.S.	2017 - 2021
Various states	2012 - 2021
Foreign	2008 - 2021

6. Property, Plant and Equipment, net

As of December 31, 2022 and 2021, our property, plant and equipment, net consisted of the following:

	Straight Line Estimated Useful Life	Composite Depreciation Rates	December 31, 2022	December 31, 2021
	(Years)	(%)	(In millions)	
Interstate Natural Gas FERC-Regulated				
Pipelines (Natural gas)		0.80-6.67	$ 11,793	$ 11,718
Equipment (Natural gas)		0.80-6.67	8,839	8,722
Other(a)		0.00-25	833	769
Accumulated depreciation, depletion and amortization			(9,883)	(9,433)
Depreciable assets			11,582	11,776
Land and land rights-of-way			388	387
Construction work in process			258	114
Total interstate natural gas FERC-regulated			12,228	12,277
Other				
Pipelines (Natural gas, liquids, crude oil and CO_2)	5-40	0.79-33.33	8,329	8,536
Equipment (Natural gas, liquids, crude oil, CO_2 and terminals)	5-40	0.79-33.33	18,645	17,789
Other(a)	3-10	0.00-33.33	4,791	4,587
Accumulated depreciation, depletion and amortization			(10,529)	(9,359)
Depreciable assets			21,236	21,553
Land and land rights-of-way			1,350	1,331
Construction work in process			785	492
Total other			23,371	23,376
Property, plant and equipment, net			$ 35,599	$ 35,653

(a) Includes general plant, general structures and buildings, computer and communication equipment, intangibles, vessels, transmix products, linefill and miscellaneous property, plant and equipment.

Depreciation, depletion and amortization expense for property, plant and equipment was $1,905 million, $1,873 million and $1,928 million for the years ended December 31, 2022, 2021 and 2020, respectively.

7. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. The following table provides details on our investments as of December 31, 2022 and 2021, and our earnings (loss) from these respective investments for the years ended December 31, 2022, 2021 and 2020:

	Ownership Interest	Equity Investments		Earnings (Loss) from Equity Investments		
	December 31,	December 31,		Year Ended December 31,		
	2022	2022	2021	2022	2021	2020
		(In millions)				
Citrus Corporation	50%	$ 1,781	$ 1,768	$ 145	$ 151	$ 165
SNG	50%	1,669	1,514	145	128	129
PHP	26.67%	666	647	70	63	—
NGPL Holdings(a)	37.5%	610	604	111	94	116
Gulf Coast Express Pipeline LLC	34%	597	618	91	86	90
MEP	50%	371	388	10	(17)	(6)
Products (SE) Pipe Line Corporation	51.17%	348	346	51	48	43
Utopia Holding LLC	50%	325	328	20	20	20
Gulf LNG Holdings Group, LLC	50%	311	347	24	22	19
EagleHawk	25%	273	266	13	8	17
Red Cedar Gathering Company	49%	155	168	17	10	12
Double Eagle Pipeline LLC	50%	90	112	18	9	12
Watco Companies, LLC	(b)	79	75	9	9	16
Cortez Pipeline Company	52.98%	31	28	30	29	24
FEP	50%	—	—	2	—	70
Ruby(c)	(d)	—	—	—	(116)	15
All others		347	369	47	47	38
Total investments		$ 7,653	$ 7,578	$ 803	$ 591	$ 780
Amortization of excess cost				$ (75)	$ (78)	$ (140)

(a) Our investment in NPGL Holdings includes a related party promissory note receivable from NGPL Holdings with quarterly interest payments at 6.75%. On March 8, 2021, we and Brookfield completed the sale of a combined 25% interest in our joint venture, NGPL Holdings, to ArcLight including a transfer of $125 million in principal amount of our related party promissory note receivable (see Note 3). We and Brookfield now each hold a 37.5% interest in NGPL Holdings. The outstanding principal amount of our related party promissory note receivable at both December 31, 2022 and 2021 was $375 million. For the years ended December 31, 2022, 2021 and 2020, we recognized $25 million, $27 million and $34 million, respectively, of interest within "Earnings from equity investments" on our accompanying consolidated statements of income.

(b) We hold a preferred equity investment in Watco Companies, LLC (Watco). We own 50,000 Class B preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash and stock distributions from the preferred shares at a rate of 3.00% per quarter. We do not hold any voting powers, but the class does provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. During the fourth quarter of 2020, we sold our Preferred A and common equity investment in Watco, and recognized a pre-tax gain of $10 million within "Other, net" on our accompanying consolidated statement of income for the year ended December 31, 2020.

(c) The loss from our investment in Ruby for the year ended December 31, 2021 includes a non-cash impairment charge of $117 million related to a write-down of our subordinated note receivable from Ruby driven by the impairment by Ruby of its assets (see Note 4 "Gains and Losses on Divestitures, Impairments, and Other Write-downs—*Investment in Ruby.*)

(d) As of December 31, 2022, we operated Ruby and owned an effective 50% interest. As of January 13, 2023, we no longer own an interest in Ruby. For further information regarding Ruby's bankruptcy filing, see Note 4 "Gains and Losses on Divestitures, Impairments, and Other Write-downs—*Investment in Ruby—Ruby Chapter 11 Bankruptcy Filing."*

Summarized combined financial information for our significant equity investments (listed or described above) is reported below (amounts represent 100% of investee financial information):

Income Statement	Year Ended December 31, 2022	2021(a)	2020
	(In millions)		
Revenues	$ 5,967	$ 5,537	$ 5,200
Costs and expenses	4,204	6,153	4,325
Net income (loss)	$ 1,763	$ (616)	$ 875

Balance Sheet	December 31, 2022	2021
	(In millions)	
Current assets	$ 1,470	$ 1,314
Non-current assets	23,361	23,154
Current liabilities	1,622	1,808
Non-current liabilities	10,207	10,001
Partners'/owners' equity	13,002	12,659

(a) 2021 amounts include a non-cash impairment charge of $2.2 billion recorded by Ruby.

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2022 and 2021 are summarized by reporting unit as follows:

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO_2	Products Pipelines	Products Pipelines Terminals	Terminals	Energy Transition Ventures	Total
	(In millions)							
Gross goodwill	$ 15,892	$ 4,940	$ 1,528	$ 2,575	$ 221	$ 1,481	$ —	$ 26,637
Accumulated impairment losses	(1,643)	(2,597)	(600)	(1,197)	(70)	(679)	—	(6,786)
December 31, 2020	14,249	2,343	928	1,378	151	802	—	19,851
Acquisitions	—	—	—	—	—	—	63	63
December 31, 2021	14,249	2,343	928	1,378	151	802	63	19,914
Acquisitions(a)	—	—	—	—	—	—	51	51
December 31, 2022	14,249	2,343	928	1,378	151	802	114	19,965
Gross goodwill	15,892	4,940	1,528	2,575	221	1,481	114	26,751
Accumulated impairment losses	(1,643)	(2,597)	(600)	(1,197)	(70)	(679)	—	(6,786)
December 31, 2022	$ 14,249	$ 2,343	$ 928	$ 1,378	$ 151	$ 802	$ 114	$ 19,965

(a) Includes goodwill arising from our acquisition of NANR and a $10 million purchase price adjustment related to our acquisition of Kinetrex in 2021 that was attributed to long-term deferred tax liabilities.

As of May 31, 2022, the results of our annual analysis did not indicate an impairment of goodwill. Each of our reporting units had an estimated fair value in excess of their respective carrying values (by at least 10%). We did not identify any triggers requiring further impairment analysis during the remainder of the year.

We estimated fair value based on a market approach utilizing forecasted earnings before interest, taxes, depreciation and amortization (EBITDA) and the enterprise value to estimated EBITDA multiples of comparable companies for each of our reporting units. The value of each reporting unit was determined from the perspective of a market participant in an orderly transaction between market participants at the measurement date.

The fair value estimates used in our Step 1 analysis are subject to variability in the forecasted EBITDA projections and in the enterprise value to estimated EBITDA multiples of comparable companies for each of our reporting units. A significant unfavorable change to any one or combination of these factors would result in a change to the reporting unit fair values discussed above and potentially result in future impairments of goodwill. Such non-cash impairments could have a significant effect on our results of operations.

9. Debt

The following table provides detail on the principal amount of our outstanding debt balances:

	December 31, 2022	December 31, 2021
	(In millions)	
Credit facility and commercial paper borrowings	$ —	$ —
Corporate senior notes(a)		
4.15%, due March 2022	—	375
1.50%, due March 2022(b)	—	853
3.95%, due September 2022	—	1,000
3.15%, due January 2023	1,000	1,000
Floating rate, due January 2023(c)	250	250
3.45%, due February 2023	625	625
3.50%, due September 2023	600	600
5.625%, due November 2023	750	750
4.15%, due February 2024	650	650
4.30%, due May 2024	600	600
4.25%, due September 2024	650	650
4.30%, due June 2025	1,500	1,500
1.75%, due November 2026	500	500
6.70%, due February 2027	7	7
2.25%, due March 2027(b)	535	569
6.67%, due November 2027	7	7
4.30%, due March 2028	1,250	1,250
7.25%, due March 2028	32	32
6.95%, due June 2028	31	31
8.05%, due October 2030	234	234
2.00%, due February 2031	750	750
7.40%, due March 2031	300	300
7.80%, due August 2031	537	537
7.75%, due January 2032	1,005	1,005
7.75%, due March 2032	300	300
4.80%, due February 2033	750	—
7.30%, due August 2033	500	500
5.30%, due December 2034	750	750
5.80%, due March 2035	500	500
7.75%, due October 2035	1	1
6.40%, due January 2036	36	36
6.50%, due February 2037	400	400
7.42%, due February 2037	47	47
6.95%, due January 2038	1,175	1,175
6.50%, due September 2039	600	600
6.55%, due September 2040	400	400
7.50%, due November 2040	375	375
6.375%, due March 2041	600	600
5.625%, due September 2041	375	375
5.00%, due August 2042	625	625
4.70%, due November 2042	475	475
5.00%, due March 2043	700	700
5.50%, due March 2044	750	750
5.40%, due September 2044	550	550
5.55%, due June 2045	1,750	1,750
5.05%, due February 2046	800	800
5.20%, due March 2048	750	750

	December 31,	
	2022	2021
3.25%, due August 2050	500	500
3.60%, due February 2051	1,050	1,050
5.45%, due January 2052	750	—
7.45%, due March 2098	26	26
TGP senior notes(a)		
7.00%, due March 2027	300	300
7.00%, due October 2028	400	400
2.90%, due March 2030	1,000	1,000
8.375%, due June 2032	240	240
7.625%, due April 2037	300	300
EPNG senior notes(a)		
8.625%, due January 2022	—	260
7.50%, due November 2026	200	200
3.50%, due February 2032	300	—
8.375%, due June 2032	300	300
CIG senior notes(a)		
4.15%, due August 2026	375	375
6.85%, due June 2037	100	100
EPC Building, LLC, promissory note, 3.967%, due January 2022 through December 2035	348	364
Trust I Preferred Securities, 4.75%, due March 2028(d)	220	221
Other miscellaneous debt(e)	242	248
Total debt – KMI and Subsidiaries	31,673	32,418
Less: Current portion of debt	3,385	2,646
Total long-term debt – KMI and Subsidiaries(f)	$ 28,288	$ 29,772

(a) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium and are subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(b) Consists of senior notes denominated in Euros that have been converted to U.S. dollars and are respectively reported above at the December 31, 2022 exchange rate of 1.0705 U.S. dollars per Euro and at the December 31, 2021 exchange rate of 1.1370 U.S. dollars per Euro. As of December 31, 2022 and 2021, the cumulative changes in the exchange rate of U.S. dollars per Euro since issuance had resulted in a decrease of $8 million and an increase of $26 million, respectively, related to the 2.25% series, and as of December 31, 2021, an increase of $38 million to our debt balance related to the 1.50% series. As of December 31, 2022, we had outstanding associated cross-currency swap agreements which are designated as cash flow hedges.

(c) As of December 31, 2022, we had outstanding an associated floating-to-fixed interest rate swap agreement which is designated as a cash flow hedge.

(d) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2022, had 4.4 million of 4.75% trust convertible preferred securities outstanding (referred to as the Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75% and carry a liquidation value of $50 per security plus accrued and unpaid distributions. The Trust I Preferred Securities outstanding as of December 31, 2022 are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; and (ii) $25.18 in cash without interest. We have the right to redeem these Trust I Preferred Securities at any time.

(e) Includes finance lease obligations with monthly installments. The lease terms expire between 2026 and 2070.

(f) Excludes our "Debt fair value adjustments" which, as of December 31, 2022 and 2021, increased our combined debt balances by $115 million and $902 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see "—Debt Fair Value Adjustments" below.

On February 23, 2022, EPNG issued in a private offering $300 million aggregate principal amount of 3.50% senior notes due 2032 and received net proceeds of $298 million after discount and issuance costs.

On August 3, 2022, we issued in a registered offering two series of senior notes consisting of $750 million aggregate principal amount of 4.80% senior notes due 2033 and $750 million aggregate principal amount of 5.45% senior notes due 2052 and received combined net proceeds of $1,484 million. We used a portion of the proceeds to repay short-term borrowings and for general corporate purposes.

On January 31, 2023, we issued in a registered offering $1,500 million aggregate principal amount of 5.20% senior notes due 2033 for net proceeds of $1,485 million, which were used to repay short-term borrowings, maturing debt and for general corporate purposes.

We and substantially all of our wholly owned domestic subsidiaries are party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement.

Current Portion of Debt

The following table details the components of our "Current portion of debt" reported on our consolidated balance sheets:

	December 31,	
	2022	2021
	(In millions)	
$3.5 billion credit facility due August 20, 2027	$ —	$ —
$500 million credit facility due November 16, 2023	—	—
Commercial paper notes	—	—
Current portion of senior notes		
8.625%, due January 2022(a)	—	260
4.15%, due March 2022(a)	—	375
1.50%, due March 2022(a)(b)	—	853
3.95% due September 2022(c)	—	1,000
3.15% due January 2023(d)	1,000	—
Floating rate, due January 2023(d)(e)	250	—
3.45% due February 2023	625	—
3.50% due September 2023	600	—
5.625%, due November 2023	750	—
Trust I Preferred Securities, 4.75% due March 2028(f)	111	111
Current portion of other debt	49	47
Total current portion of debt	$ 3,385	$ 2,646

(a) We repaid the principal amount of these senior notes during the first quarter of 2022.
(b) Denominated in Euros.
(c) We repaid the principal amount of these senior notes on June 1, 2022.
(d) On January 17, 2023, we repaid these senior notes using cash on hand and short-term borrowings.
(e) These senior notes have an associated floating-to-fixed interest rate swap agreement which is designated as a cash flow hedge.
(f) Reflects the portion of cash consideration payable if all the outstanding securities as of the end of the reporting period were converted by the holders.

Credit Facilities and Restrictive Covenants

On December 15, 2022, we amended our credit facilities, discussed further below, to provide for, among other things, the replacement of LIBOR-based provisions with term SOFR provisions, related updates to benchmark replacement provisions and the extension of the maturity date on our $3.5 billion credit facility from August 2026 to August 2027.

Our revolving credit facilities consist of (i) a $3.5 billion revolving credit facility due August 2027 with a syndicate of lenders, which can be increased by up to $1.0 billion if certain conditions, including the receipt of additional lender commitments, are met, and (ii) a $500 million amended revolving credit facility due November 2023. Borrowings under our credit facilities can be used for working capital and other general corporate purposes and as backup to our commercial paper program.

We maintain a $3.5 billion commercial paper program through the private placement of short-term notes. On September 26, 2022, we reduced our commercial paper program from $4.0 billion to $3.5 billion to conform its size to that of our $3.5 billion revolving credit facility, which matures in August 2027. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facilities.

Depending on the type of loan request, our borrowings under our credit facilities bear interest at either (i) SOFR, plus (x) a credit spread adjustment and (y) an applicable margin ranging from 1.000% to 1.750% (for our $3.5 billion credit facility) or to 2.000% (for our $500 million credit facility) per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; or (3) SOFR for a one-month eurodollar loan, plus (x) a credit spread adjustment, (y) 1%, and (z) in each case, an applicable margin ranging from 0.100% to 0.750% (for our $3.5 billion credit facility) or to 1.000% (for our $500 million credit facility) per annum based on our credit rating. Standby fees for the unused portion of the credit facility will be calculated at a rate ranging from 0.100% to 0.250% (for our $3.5 billion credit facility) or to 0.300% (for our $500 million credit facility).

Our credit facilities contain financial and various other covenants that apply to us and our subsidiaries and are common in such agreements, including a maximum ratio of Consolidated Net Indebtedness to Consolidated EBITDA (as defined in the credit facilities, as amended) of 5.50 to 1.00, for any four-fiscal-quarter period. Other negative covenants include restrictions on our and certain of our subsidiaries' ability to incur debt, grant liens, make fundamental changes or engage in certain transactions with affiliates, or in the case of certain material subsidiaries, permit restrictions on dividends, distributions or making or prepayments of loans to us or any guarantor. Our credit facilities also restrict our ability to make certain restricted payments if an event of default (as defined in the credit facilities) has occurred and is continuing or would occur and be continuing.

As of December 31, 2022, we had no borrowings outstanding under our credit facilities, no borrowings outstanding under our commercial paper program and $81 million in letters of credit. Our availability under our credit facilities as of December 31, 2022 was approximately $3.9 billion. As of December 31, 2022, we were in compliance with all required covenants.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2022, are summarized as follows:

Year		**Total**
		(In millions)
2023	$	3,385
2024		1,925
2025		1,566
2026		1,102
2027		890
Thereafter		22,805
Total	$	31,673

Debt Fair Value Adjustments

The following table summarizes the "Debt fair value adjustments" included on our accompanying consolidated balance sheets:

	December 31,			
		2022		**2021**
	(In millions)			
Purchase accounting debt fair value adjustments	$	472	$	498
Carrying value adjustment to hedged debt		(367)		376
Unamortized portion of proceeds received from the early termination of interest rate swap agreements(a)		204		223
Unamortized debt discounts, net		(68)		(71)
Unamortized debt issuance costs		(126)		(124)
Total debt fair value adjustments	$	115	$	902

(a) As of December 31, 2022, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 12 years.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances is disclosed below:

	December 31, 2022		December 31, 2021	
	Carrying value	**Estimated fair value(a)**	**Carrying value**	**Estimated fair value(a)**
		(In millions)		
Total debt	$ 31,788	$ 30,070	$ 33,320	$ 37,775

(a) Included in the estimated fair value are amounts for our Trust I Preferred Securities of $195 million and $218 million as of December 31, 2022 and 2021, respectively.

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2022 and 2021.

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 4.76% during 2022 and 4.67% during 2021. Information on our interest rate swaps is contained in Note 14. For information about our contingent debt agreements, see Note 13 "Commitments and Contingent Liabilities—*Contingent Debt*").

10. Share-based Compensation and Employee Benefits

Share-based Compensation

Class P Common Stock

Following is a summary of our stock compensation plans:

	Directors' Plan	**Long Term Incentive Plan**
Participating individuals	Eligible non-employee directors	Eligible employees
Total number of shares of Class P common stock authorized	1,190,000	63,000,000
Vesting period	6 months	1 year to 10 years

Kinder Morgan, Inc. Second Amended and Restated Stock Compensation Plan for Non-Employee Directors

We have a Kinder Morgan, Inc. Second Amended and Restated Stock Compensation Plan for Non-Employee Directors (Directors' Plan). The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board of directors, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect annually to receive shares of Class P common stock. During the year ended December 31, 2022, we made restricted Class P common stock grants to our non-employee directors of 34,820.

Kinder Morgan, Inc. 2021 Amended and Restated Stock Incentive Plan

We also have a Kinder Morgan, Inc. 2021 Amended and Restated Stock Incentive Plan (Long Term Incentive Plan). The following table sets forth a summary of activity and related balances under our Long Term Incentive Plan:

	Shares	Weighted Average Grant Date Fair Value per Share
	(In thousands, except per share amounts)	
Outstanding at December 31, 2021	12,617	$ 17.63
Granted	4,110	17.31
Vested	(2,744)	20.94
Forfeited	(695)	17.17
Outstanding at December 31, 2022	13,288	$ 16.87

The following tables set forth additional information related to our Long Term Incentive Plan:

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts)		
Weighted average grant date fair value per share	$ 17.31	$ 17.44	$ 15.10
Intrinsic value of awards vested during the year	47	77	59
Restricted stock awards expense(a)	60	59	73
Restricted stock awards capitalized(a)	9	9	11

(a) We allocate labor and benefit costs to joint ventures that we operate in accordance with our partnership agreements.

	December 31, 2022
Unrecognized restricted stock awards compensation costs, less estimated forfeitures *(in millions)*	$ 104
Weighted average remaining amortization period	1.99 years

Pension and Other Postretirement Benefit (OPEB) Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain collectively bargained participants receive Company contributions in accordance with collective bargaining agreements. A participant becomes fully vested in Company contributions after two years and may take a distribution upon termination of employment or retirement. The total cost for our savings plan was approximately $51 million, $48 million and $53 million for the years ended December 31, 2022, 2021 and 2020, respectively.

Pension Plans

Our pension plans are defined benefit plans that cover substantially all of our U.S. employees and provide benefits under a cash balance formula. A participant in the cash balance formula accrues benefits through contribution credits based on a combination of age and years of service, multiplied by eligible compensation. Interest is also credited to the participant's plan account. A participant becomes fully vested in the plan after three years and may take a lump sum or annuity distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees accrue benefits through career pay or final pay formulas.

OPEB Plans

We and certain of our subsidiaries provide OPEB benefits, including medical benefits for closed groups of retired employees and certain grandfathered employees and their dependents, and limited postretirement life insurance benefits for retired employees. These plans provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange. Medical benefits under these OPEB plans may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and we reserve the right to change these benefits.

Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2022 and 2021:

	Pension Benefits		OPEB	
	2022	2021	2022	2021
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 2,658	$ 2,844	$ 257	$ 299
Service cost	55	53	1	1
Interest cost	57	45	5	4
Actuarial gain	(503)	(80)	(44)	(21)
Benefits paid	(190)	(204)	(26)	(28)
Participant contributions	—	—	1	1
Other	—	—	1	1
Benefit obligation at end of period	2,077	2,658	195	257
Change in plan assets:				
Fair value of plan assets at beginning of period	2,231	2,199	382	361
Actual return on plan assets	(350)	180	(63)	40
Employer contributions	50	56	7	7
Participant contributions	—	—	1	1
Other	—	—	1	1
Benefits paid	(190)	(204)	(26)	(28)
Fair value of plan assets at end of period	1,741	2,231	302	382
Funded status - net (liability) asset at December 31,	$ (336)	$ (427)	$ 107	$ 125
Amounts recognized in the consolidated balance sheets:				
Non-current benefit asset(a)	$ —	$ —	$ 239	$ 302
Current benefit liability	—	—	(15)	(18)
Non-current benefit liability	(336)	(427)	(117)	(159)
Funded status - net (liability) asset at December 31,	$ (336)	$ (427)	$ 107	$ 125
Amounts of pre-tax accumulated other comprehensive (loss) income recognized in the consolidated balance sheets:				
Unrecognized net actuarial (loss) gain	$ (455)	$ (495)	$ 135	$ 176
Unrecognized prior service (cost) credit	(1)	(2)	4	6
Accumulated other comprehensive (loss) income	$ (456)	$ (497)	$ 139	$ 182
Information related to plans whose accumulated benefit obligations exceeded the fair value of plan assets:				
Accumulated benefit obligation	$ 2,047	$ 2,608	$ 167	$ 219
Fair value of plan assets	1,741	2,231	34	42

(a) 2022 and 2021 OPEB amounts include $45 million and $54 million, respectively, of non-current benefit assets related to a plan we sponsor which is associated with employee services provided to an unconsolidated joint venture, and for which we have recorded an offsetting related party deferred credit.

The 2022 net actuarial gain for the pension plans was primarily due to an increase in the weighted average discount rate used to determine the benefit obligation as of December 31, 2022. The 2022 net actuarial gain for the OPEB plans was primarily due to an increase in the weighted average discount rate used to determine the benefit obligations as of December 31, 2022 and changes in the claims cost assumptions. The 2021 net actuarial gain for the pension plans was primarily due to an increase in the weighted average discount rate used to determine the benefit obligation as of December 31, 2021, partially offset by changes made to the assumptions used to determine at what age and in what form benefits commence. The 2021 net actuarial gain for the OPEB plans was primarily due to an increase in the weighted average discount rate used to determine the benefit obligations as of December 31, 2021 and changes in the claims cost assumptions.

Plan Assets. The investment policies and strategies are established by our plan's fiduciary committee for the assets of each of the pension and OPEB plans, which are responsible for investment decisions and management oversight of the plans. The stated philosophy of the fiduciary committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (i) meet or exceed plan actuarial earnings assumptions over the long term and (ii) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the fiduciary committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the fiduciary committee has adopted a strategy of using multiple asset classes.

The allowable range for asset allocations in effect for our plans as of December 31, 2022, by asset category, are as follows:

	Pension Benefits	OPEB
Cash		0% to 23%
Equities	42% to 52%	42% to 72%
Fixed income securities	37% to 47%	25% to 50%
Real estate	2% to 12%	
Company securities (KMI Class P common stock and/or debt securities)	0% to 10%	

Below are the details of our pension and OPEB plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this level are cash, equities and exchange traded mutual funds. These investments are valued at the closing price reported on the active market on which the individual securities are traded.

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are short-term investment funds, fixed income securities and derivatives. Short-term investment funds are valued at amortized cost, which approximates fair value. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market. Derivatives are exchange-traded through clearinghouses and are valued based on these prices.

- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as a practical expedient to measure fair value, as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include common/collective trust funds, private investment funds and limited partnerships. The plan assets measured at NAV are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2022 and 2021:

	Pension Assets					
	2022			2021		
	Level 1	Level 2	Total	Level 1	Level 2	Total
	(In millions)					
Measured within fair value hierarchy						
Cash	$ —	$ —	$ —	$ 11	$ —	$ 11
Short-term investment funds	—	27	27	—	25	25
Equities(a)	152	—	152	153	—	153
Fixed income securities	—	421	421	—	566	566
Subtotal	$ 152	$ 448	600	$ 164	$ 591	755
Measured at NAV						
Common/collective trusts(b)			1,138			1,389
Private investment funds(c)			—			39
Private limited partnerships(d)			3			48
Subtotal			1,141			1,476
Total plan assets fair value			$ 1,741			$ 2,231

(a) Plan assets include $110 million and $97 million of KMI Class P common stock for 2022 and 2021, respectively.
(b) Common/collective trust funds were invested in approximately 66% equities, 22% fixed income securities and 12% real estate in 2022 and 83% equities and 17% fixed income securities in 2021.
(c) Private investment funds were invested in 100% fixed income securities in 2021.
(d) Includes assets invested in real estate, venture and buyout funds.

	OPEB Assets					
	2022			2021		
	Level 1	Level 2	Total	Level 1	Level 2	Total
	(In millions)					
Measured within fair value hierarchy						
Short-term investment funds	$ —	$ 3	$ 3	$ —	$ 3	$ 3
Measured at NAV						
Common/collective trusts(a)			299			379
Total plan assets fair value			$ 302			$ 382

(a) Common/collective trust funds were invested in approximately 61% equities and 39% fixed income securities for 2022 and 63% equities and 37% fixed income securities for 2021.

Employer Contributions and Expected Payment of Future Benefits. As of December 31, 2022, we expect the following cash flows under our plans:

	Pension Benefits	OPEB
	(In millions)	
Contributions expected in 2023	$ 50	$ —
Benefit payments expected in:		
2023	$ 210	$ 26
2024	206	24
2025	202	23
2026	199	21
2027	191	20
2028 - 2032	861	76

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation as of December 31, 2022 and 2021 and net benefit costs of our pension and OPEB plans for 2022, 2021 and 2020:

	Pension Benefits		OPEB	
	2022	**2021**	**2022**	**2021**
Assumptions related to benefit obligations:				
Discount rate	5.41 %	2.74 %	5.38 %	2.56 %
Rate of compensation increase	3.50 %	3.50 %	n/a	n/a
Interest crediting rate	3.50 %	3.01 %	n/a	n/a

	Pension Benefits			OPEB		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
Assumptions related to benefit costs:						
Discount rate	2.74 %	2.27 %	3.17 %	2.56 %	2.08 %	3.03 %
Expected return on plan assets	6.50 %	6.25 %	6.75 %	5.75 %	5.75 %	6.50 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a
Interest crediting rate	3.01 %	2.57 %	3.71 %	n/a	n/a	n/a

We utilize a full yield curve approach in estimating the service and interest cost components of net periodic benefit cost (credit) for our retirement benefit plans by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class. The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the OPEB assets subject to unrelated business income taxes, we utilize an after-tax expected return on plan assets to determine our benefit costs.

Actuarial estimates for our OPEB plans assume an annual increase in the per capita cost of covered health care benefits. The initial annual rate of increase is 5.87% which gradually decreases to 4.00% by the year 2047.

Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows:

	Pension Benefits			OPEB		
	2022	2021	2020	2022	2021	2020
	(In millions)					
Components of net benefit cost (credit):						
Service cost	$ 55	$ 53	$ 59	$ 1	$ 1	$ 1
Interest cost	57	45	71	5	4	8
Expected return on assets	(142)	(133)	(137)	(17)	(16)	(16)
Amortization of prior service cost (credit)	1	—	1	(3)	(5)	(5)
Amortization of net actuarial loss (gain)	29	52	40	(18)	(17)	(13)
Net benefit cost (credit)	—	17	34	(32)	(33)	(25)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net (gain) loss arising during period	(11)	(127)	157	24	(40)	(43)
Amortization or settlement recognition of net actuarial (loss) gain	(29)	(52)	(40)	17	17	13
Amortization of prior service (cost) credit	(1)	—	(1)	2	3	3
Total recognized in total other comprehensive (income) loss(a)	(41)	(179)	116	43	(20)	(27)
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	$ (41)	$ (162)	$ 150	$ 11	$ (53)	$ (52)

(a) Excludes $4 million, $3 million and $2 million for the years ended December 31, 2022, 2021 and 2020 respectively, associated with other plans.

11. Stockholders' Equity

Class P Common Stock

On July 19, 2017, our board of directors approved a $2 billion share buy-back program that began in December 2017. On January 18, 2023, our board of directors approved an increase in our share repurchase authorization to $3 billion. Activity under the buy-back program is as follows:

	Year Ended December 31,		
	2022	2021	2020
	(In millions, except per share amounts)		
Total value of shares repurchased	$ 368	$ —	$ 50
Total number of shares repurchased	21	—	4
Average repurchase price per share	$ 16.94	$ —	$ 13.93

Since December 2017, in total, we have repurchased 54 million of our shares under the program at an average price of $17.40 per share for $943 million, leaving capacity under the program, after our subsequent increase, of $2.1 billion.

On December 19, 2014, we entered into an equity distribution agreement authorizing us to issue and sell through or to the managers party thereto, as sales agents and/or principals, shares having an aggregate offering price of up to $5 billion from time to time during the term of this agreement. During the years ended December 31, 2022, 2021 and 2020 we did not issue any shares under this agreement.

Dividends

The following table provides information about our per share dividends:

	Year Ended December 31,		
	2022	2021	2020
Per share cash dividend declared for the period	$ 1.11	$ 1.08	$ 1.05
Per share cash dividend paid in the period	1.1025	1.0725	1.0375

On January 18, 2023, our board of directors declared a cash dividend of $0.2775 per share for the quarterly period ended December 31, 2022, which is payable on February 15, 2023 to shareholders of record as of January 31, 2023.

Adoption of Accounting Pronouncement

On January 1, 2022, we adopted Accounting Standards Update (ASU) No. 2020-06, "*Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity.*" This ASU (i) simplifies an issuer's accounting for convertible instruments by eliminating two of the three models in Subtopic 470-20 that require separate accounting for embedded conversion features, (ii) amends diluted earnings per share calculations for convertible instruments by requiring the use of the if-converted method and (iii) simplifies the settlement assessment entities are required to perform on contracts that can potentially settle in an entity's own equity by removing certain requirements. Using the modified retrospective method, the adoption of this ASU resulted in a pre-tax adjustment of $14 million to unwind the remaining unamortized debt discount within "Debt fair value adjustments" on our consolidated balance sheet and an adjustment of $11 million to unwind the balance of the conversion feature classified in "Additional paid in capital" on our consolidated statement of stockholders' equity for the year ended December 31, 2022.

Accumulated Other Comprehensive Loss

Changes in the components of our "Accumulated other comprehensive loss" not including noncontrolling interests are summarized as follows:

	Net unrealized gains/(losses) on cash flow hedge derivatives	Pension and other postretirement liability adjustments	Total Accumulated other comprehensive loss
		(In millions)	
Balance at December 31, 2019	$ (7)	$ (326)	$ (333)
Other comprehensive gain (loss) before reclassifications	249	(68)	181
Gains reclassified from accumulated other comprehensive loss	(255)	—	(255)
Net current-period change in accumulated other comprehensive loss	(6)	(68)	(74)
Balance at December 31, 2020	(13)	(394)	(407)
Other comprehensive (loss) gain before reclassifications	(432)	155	(277)
Losses reclassified from accumulated other comprehensive loss	273	—	273
Net current-period change in accumulated other comprehensive loss	(159)	155	(4)
Balance at December 31, 2021	(172)	(239)	(411)
Other comprehensive (loss) gain before reclassifications	(312)	1	(311)
Losses reclassified from accumulated other comprehensive loss	320	—	320
Net current-period change in accumulated other comprehensive loss	8	1	9
Balance at December 31, 2022	$ (164)	$ (238)	$ (402)

12. Related Party Transactions

Affiliate Balances

We have transactions with affiliates which consist of (i) unconsolidated affiliates in which we hold an investment accounted for under the equity method of accounting (see Note 7 for additional information related to these investments); and (ii) external partners of our joint ventures we consolidate.

The following tables summarize our affiliate balance sheet balances and income statement activity, other than amounts reported within our "Investments" balances and "Earnings from equity investments" activity:

	December 31,	
	2022	2021
	(In millions)	
Balance sheet location		
Accounts receivable	$ 39	$ 38
Other current assets	3	4
	$ 42	$ 42
Current portion of debt	$ 6	$ 6
Accounts payable	19	21
Other current liabilities	8	4
Long-term debt	142	148
Other long-term liabilities and deferred credits	47	56
	$ 222	$ 235

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Income statement location			
Revenues	$ 172	$ 164	$ 206
Operating Costs, Expenses and Other			
Costs of sales	$ 134	$ 145	$ 116
Other operating expenses	50	52	119

13. Commitments and Contingent Liabilities

Rights-Of-Way Obligations

Our rights-of-way obligations primarily consist of non-lease agreements that existed at the time of Topic 842*, Leases,* adoption, at which time we elected a practical expedient which allowed us to continue our historical treatment. Our future minimum rental commitments related to our rights-of-way obligations were $120 million as of December 31, 2022.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2022 and 2021, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $163 million and $170 million, respectively. December 31, 2022 and 2021 amounts are represented by our proportional share of the debt obligations of one equity investee, Cortez Pipeline Company (Cortez). Under such guarantees we are severally liable for our percentage ownership share of Cortez's debt in the event of its non-performance. The contingent debt obligations balances as of December 31, 2022 and 2021 each included $120 million for 100% guaranteed debt obligations for a subsidiary of Cortez.

Guarantees and Indemnifications

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are also circumstances where the amount and duration are unlimited. Other than with our rights-of-way obligations and contingent debt described above, we are currently not subject to any material requirements to perform under quantifiable arrangements. We are unable to estimate a maximum exposure for our other guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

See Note 18 for a description of matters that we have identified as contingencies requiring accrual of liabilities and/or disclosure, including any such matters arising under guarantee or indemnification agreements.

14. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to some of these risks.

Energy Commodity Price Risk Management

As of December 31, 2022, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil fixed price	(18.4) MMBbl
Crude oil basis	(4.2) MMBbl
Natural gas fixed price	(62.6) Bcf
Natural gas basis	(40.1) Bcf
NGL fixed price	(0.6) MMBbl
Derivatives not designated as hedging contracts	
Crude oil fixed price	(1.0) MMBbl
Crude oil basis	(9.2) MMBbl
Natural gas fixed price	(7.1) Bcf
Natural gas basis	(44.7) Bcf
NGL fixed price	(0.8) MMBbl

As of December 31, 2022, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2026.

Interest Rate Risk Management

We utilize interest rate derivatives to hedge our exposure to both changes in the fair value of our fixed rate debt instruments and variability in expected future cash flows attributable to variable interest rate payments. The following table summarizes our outstanding interest rate contracts as of December 31, 2022:

	Notional amount	Accounting treatment	Maximum term
	(In millions)		
Derivatives designated as hedging instruments			
Fixed-to-variable interest rate contracts(a)(b)	$ 7,500	Fair value hedge	March 2035
Variable-to-fixed interest rate contracts	250	Cash flow hedge	January 2023
Derivatives not designated as hedging instruments			
Variable-to-fixed interest rate contracts	1,250	Mark-to-Market	December 2023

(a) The principal amount of hedged senior notes consisted of $1,300 million included in “Current portion of debt” and $6,200 million included in “Long-term debt” on our accompanying consolidated balance sheet.
(b) During the year ended December 31, 2022, certain optional expedients as set forth in Topic 848 – Reference Rate Reform were elected on certain of these contracts to preserve fair value hedge accounting treatment. See Note 19 “Recent Accounting Pronouncements” for further information on Topic 848.

Foreign Currency Risk Management

We utilize foreign currency derivatives to hedge our exposure to variability in foreign exchange rates. The following table summarizes our outstanding foreign currency contracts as of December 31, 2022:

	Notional amount	Accounting treatment	Maximum term
	(In millions)		
Derivatives designated as hedging instruments			
EUR-to-USD cross currency swap contracts(a)	$ 543	Cash flow hedge	March 2027

(a) These swaps eliminate the foreign currency risk associated with our Euro-denominated debt.

Impact of Derivative Contracts on Our Consolidated Financial Statements

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets:

Fair Value of Derivative Contracts

		Derivatives Asset		Derivatives Liability	
		December 31,		December 31,	
		2022	2021	2022	2021
	Location	Fair value		Fair value	
		(In millions)			
Derivatives designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/(Fair value of derivative contracts)	$ 150	$ 61	$ (156)	$ (141)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	6	3	(91)	(94)
Subtotal		156	64	(247)	(235)
Interest rate contracts	Fair value of derivative contracts/(Fair value of derivative contracts)	—	101	(144)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	39	284	(261)	(15)
Subtotal		39	385	(405)	(18)
Foreign currency contracts	Fair value of derivative contracts/(Fair value of derivative contracts)	—	35	(3)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	6	(32)	—
Subtotal		—	41	(35)	(3)
Total		195	490	(687)	(256)
Derivatives not designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/(Fair value of derivative contracts)	80	11	(162)	(31)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	23	1	(19)	(6)
Subtotal		103	12	(181)	(37)
Interest rate contracts	Fair value of derivative contracts/(Fair value of derivative contracts)	1	12	—	—
Total		104	24	(181)	(37)
Total derivatives		$ 299	$ 514	$ (868)	$ (293)

The following two tables summarize the fair value measurements of our derivative contracts based on the three levels established by the ASC. The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(a)	Net amount
	Balance sheet asset fair value measurements by level						
	(In millions)						
As of December 31, 2022							
Energy commodity derivative contracts(b)	$ 115	$ 144	$ —	$ 259	$ (186)	$ —	$ 73
Interest rate contracts	—	40	—	40	—	—	40
As of December 31, 2021							
Energy commodity derivative contracts(b)	$ 56	$ 20	$ —	$ 76	$ (53)	$ (20)	$ 3
Interest rate contracts	—	397	—	397	(9)	—	388
Foreign currency contracts	—	41	—	41	(3)	—	38

	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral posted(a)	Net amount
	Balance sheet liability fair value measurements by level						
	(In millions)						
As of December 31, 2022							
Energy commodity derivative contracts(b)	$ (23)	$ (405)	$ —	$ (428)	$ 186	$ (30)	$ (272)
Interest rate contracts	—	(405)	—	(405)	—	—	(405)
Foreign currency contracts	—	(35)	—	(35)	—	—	(35)
As of December 31, 2021							
Energy commodity derivative contracts(b)	(15)	(257)	—	(272)	53	—	(219)
Interest rate contracts	—	(18)	—	(18)	9	—	(9)
Foreign currency contracts	—	(3)	—	(3)	3	—	—

(a) Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amount associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.
(b) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps, NGL swaps and crude oil basis swaps.

The following tables summarize the pre-tax impact of our derivative contracts in our accompanying consolidated statements of income and comprehensive income:

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2022	2021	2020
		(In millions)		
Interest rate contracts	Interest, net	$ (738)	$ (322)	$ 335
Hedged fixed rate debt(a)	Interest, net	$ 743	$ 326	$ (343)

(a) As of December 31, 2022, the cumulative amount of fair value hedging adjustments to our hedged fixed rate debt was a decrease of $367 million included in "Debt fair value adjustments" on our accompanying consolidated balance sheets.

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative(a)			Location	Gain/(loss) reclassified from Accumulated OCI into income(b)		
	Year Ended December 31,				Year Ended December 31,		
	2022	2021	2020		2022	2021	2020
	(In millions)				(In millions)		
Energy commodity derivative contracts	$ (338)	$ (475)	$ 240	Revenues—Commodity sales	$ (491)	$ (271)	$ 222
				Costs of sales	144	20	(14)
Interest rate contracts(c)	7	5	(8)	Interest, net	—	—	—
Foreign currency contracts	(73)	(93)	92	Other, net	(68)	(105)	125
Total	$ (404)	$ (563)	$ 324	Total	$ (415)	$ (356)	$ 333

(a) We expect to reclassify an approximately $92 million loss associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2022 into earnings during the next twelve months (when the associated forecasted transactions are also expected to impact earnings); however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) During the years ended December 31, 2022, 2021 and 2020, we recognized approximate gains of $121 million, $41 million and no gains, respectively, associated with a write-down of hedged inventory. All other amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives		
		Year Ended December 31,		
		2022	2021	2020
		(In millions)		
Energy commodity derivative contracts	Revenues—Commodity sales	$ 137	$ (652)	$ (1)
	Costs of sales	(190)	152	25
	Earnings from equity investments(a)	(11)	(5)	—
Interest rate contracts	Interest, net	(10)	12	—
Total(b)		$ (74)	$ (493)	$ 24

(a) Amounts represent our share of an equity investee's income (loss).

(b) The years ended December 31, 2022, 2021 and 2020 include approximate losses of $11 million, $479 million and $11 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2022 and 2021, we had no outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2022, we had cash margins of $1 million posted by our counterparties with us as collateral and reported within "Other current liabilities" on our accompanying consolidated balance sheet. As of December 31, 2021 we had cash margins of $14 million posted by our counterparties with us as collateral and reported within "Other current liabilities" on our accompanying consolidated balance sheet. The balance at December 31, 2022 represents the initial margin requirements of $29 million, offset by counterparty variation margin requirements of $30 million. We also use industry standard commercial agreements that allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of December 31, 2022, based on our current mark-to- market positions and posted collateral, we estimate that if our credit rating were downgraded one notch, we would not be required to post additional collateral. If we were downgraded two notches, we estimate that we would be required to post $144 million of additional collateral.

15. Revenue Recognition

Nature of Revenue by Segment

Natural Gas Pipelines Segment

We provide various types of natural gas transportation and storage services, natural gas and NGL sales contracts, and various types of gathering and processing services for producers, including receiving, compressing, transporting and re-delivering quantities of natural gas and/or NGLs made available to us by producers to a specified delivery location.

Natural Gas Transportation and Storage Contracts

The natural gas we receive under our transportation and storage contracts remains under the control of our customers. Under firm service contracts, the customer generally pays a two-part transaction price that includes (i) a fixed take-or-pay reservation fee and (ii) a fee-based per-unit rate for quantities of natural gas actually transported or injected into/withdrawn from storage. Under non-firm service contracts, generally described as interruptible service, the customer pays a transaction price on a fee-based per-unit rate for the quantities actually transported or injected into/withdrawn from storage.

Natural Gas and NGL Sales Contracts

Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales. These customer contracts generally provide for the customer to nominate a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Gathering and Processing Contracts

We provide various types of gathering and processing services for producers, including receiving, processing, compressing, transporting and re-delivering quantities of natural gas made available to us by producers to a specified delivery location. This integrated service can be firm if subject to a minimum volume commitment or acreage dedication or non-firm when offered on an as requested, non-guaranteed basis. In our gathering contracts we generally promise to provide the contracted integrated services each day over the life of the contract. The customer pays a transaction price typically based on a per-unit rate for the quantities actually gathered and/or processed, including amounts attributable to deficiency quantities associated with minimum volume contracts.

Products Pipelines Segment

We provide crude oil and refined petroleum transportation and storage services on a firm or non-firm basis. For our firm transportation service, the customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it flows volumes into our pipeline. The customer pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities. Our firm storage service generally includes a fixed take-or-pay monthly reservation fee for the portion of storage capacity reserved by the customer and a per-unit rate for actual quantities injected into/withdrawn from storage. Under the non-firm transportation and storage service the customer typically pays a per-unit rate for actual quantities of product injected into/withdrawn from storage and/or transported.

We sell transmix, crude oil or other commodity products. The customer’s contracts generally include a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Liquids Tank Services

Firm Storage and Handling Contracts: We have liquids tank storage and handling service contracts that include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, the customers have fixed take-or-pay monthly obligation which generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Firm Handling Contracts: For our firm handling service contracts, we typically promise to handle on a stand-ready basis throughput volumes up to the customer's minimum volume commitment amount. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it used the handling service. The customer pays a transaction price typically based on a per-unit rate for volumes handled, including amounts attributable to deficiency quantities.

Bulk Services

Our bulk storage and handling contracts generally include inbound handling of our customers' dry bulk material product (e.g., petcoke, metals, ores) into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm basis, including amounts attributable to deficiency quantities, and non-firm basis where the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

CO_2 Segment

Our crude oil, NGL, CO_2 and natural gas production customer sales contracts typically include a specified quantity and quality of commodity product to be delivered and sold to the customer at a specified delivery point. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Disaggregation of Revenues

The following tables present our revenues disaggregated by revenue source and type of revenue for each revenue source:

	Year Ended December 31, 2022					
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Corporate and Eliminations	Total
	(In millions)					
Revenues from contracts with customers(a)						
Services						
Firm services(b)	$ 3,547	$ 207	$ 763	$ 1	$ (3)	$ 4,515
Fee-based services	926	962	426	46	—	2,360
Total services	4,473	1,169	1,189	47	(3)	6,875
Commodity sales						
Natural gas sales	6,266	—	—	94	(20)	6,340
Product sales	1,433	2,032	29	1,426	(7)	4,913
Total commodity sales	7,699	2,032	29	1,520	(27)	11,253
Total revenues from contracts with customers	12,172	3,201	1,218	1,567	(30)	18,128
Other revenues(c)						
Leasing services(d)	474	194	574	60	—	1,302
Derivatives adjustments on commodity sales	(26)	(3)	—	(325)	—	(354)
Other	66	26	—	32	—	124
Total other revenues	514	217	574	(233)	—	1,072
Total revenues	$ 12,686	$ 3,418	$ 1,792	$ 1,334	$ (30)	$ 19,200

	Year Ended December 31, 2021					
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Corporate and Eliminations	Total
	(In millions)					
Revenues from contracts with customers(a)						
Services						
Firm services(b)	$ 3,402	$ 259	$ 751	$ 1	$ (2)	$ 4,411
Fee-based services	746	949	375	45	(1)	2,114
Total services	4,148	1,208	1,126	46	(3)	6,525
Commodity sales						
Natural gas sales	6,463	—	—	32	(15)	6,480
Product sales	1,260	845	24	1,070	(50)	3,149
Total commodity sales	7,723	845	24	1,102	(65)	9,629
Total revenues from contracts with customers	11,871	2,053	1,150	1,148	(68)	16,154
Other revenues(c)						
Leasing services(d)	473	172	565	56	—	1,266
Derivatives adjustments on commodity sales	(700)	(1)	—	(222)	—	(923)
Other	65	21	—	27	—	113
Total other revenues	(162)	192	565	(139)	—	456
Total revenues	$ 11,709	$ 2,245	$ 1,715	$ 1,009	$ (68)	$ 16,610

	Year Ended December 31, 2020					
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Corporate and Eliminations	Total
	(In millions)					
Revenues from contracts with customers(a)						
Services						
Firm services(b)	$ 3,345	$ 271	$ 756	$ 1	$ (3)	$ 4,370
Fee-based services	714	905	395	42	—	2,056
Total services	4,059	1,176	1,151	43	(3)	6,426
Commodity sales						
Natural gas sales	2,038	—	—	1	(7)	2,032
Product sales	562	358	14	735	(30)	1,639
Total commodity sales	2,600	358	14	736	(37)	3,671
Total revenues from contracts with customers	6,659	1,534	1,165	779	(40)	10,097
Other revenues(c)						
Leasing services(d)	466	166	557	47	—	1,236
Derivatives adjustments on commodity sales	18	—	—	203	—	221
Other	116	21	—	9	—	146
Total other revenues	600	187	557	259	—	1,603
Total revenues	$ 7,259	$ 1,721	$ 1,722	$ 1,038	$ (40)	$ 11,700

(a) Differences between the revenue classifications presented on the consolidated statements of income and the categories for the disaggregated revenues by type of revenue above are primarily attributable to revenues reflected in the “Other revenues” category above (see note (c)).

(b) Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. Excludes service contracts with indexed-based pricing, which along with revenues from other customer service contracts are reported as Fee-based services.

(c) Amounts recognized as revenue under guidance prescribed in Topics of the ASC other than in Topic 606 were primarily from leases and derivative contracts. See Note 14 for additional information related to our derivative contracts.

(d) Our revenues from leasing services are predominantly comprised of specific assets that we lease to customers under operating leases where one customer obtains substantially all of the economic benefit from the asset and has the right to direct the use of that asset. These leases primarily consist of specific tanks, treating facilities, marine vessels and gas equipment and pipelines with separate control locations. We do not lease assets that qualify as sales-type or finance leases.

Contract Balances

As of December 31, 2022 and 2021, our contract asset balances were $33 million and $39 million, respectively. Of the contract asset balance at December 31, 2021, $14 million was transferred to accounts receivable during the year ended December 31, 2022. As of December 31, 2022 and 2021, our contract liability balances were $204 million and $212 million, respectively. Of the contract liability balance at December 31, 2021, $90 million was recognized as revenue during the year ended December 31, 2022.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our "contractually committed" revenue as of December 31, 2022 that we will invoice or transfer from contract liabilities and recognize in future periods:

Year		**Estimated Revenue**
		(In millions)
2023	$	4,312
2024		3,401
2025		2,800
2026		2,466
2027		2,132
Thereafter		12,340
Total	$	27,451

Our contractually committed revenue, for purposes of the tabular presentation above, is generally limited to service or commodity sale customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedient that we elected to apply, remaining performance obligations for contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

16. Reportable Segments

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG regasification, liquefaction and storage facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. that store and handle various commodities including gasoline, diesel fuel, renewable fuel stocks, chemicals, ethanol, metals and petroleum coke; and (ii) Jones Act-qualified tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gasoline processing plants in West Texas; (iii) the ownership and operation of a crude oil pipeline system in West Texas; and (iv) the ownership and operation of RNG and LNG facilities in Indiana associated with our acquisition of Kinetrex in 2021 and the ownership and operation of GTE facilities in Michigan and Kentucky associated with our acquisition of NANR in 2022 (see Note 3).

We evaluate performance principally based on each segment's EBDA, which excludes general and administrative expenses and corporate charges, interest expense, net, and income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and services and marketing strategies.

We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at book value.

During 2022, 2021 and 2020, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$ 12,659	$ 11,644	$ 7,222
Intersegment revenues	27	65	37
Products Pipelines	3,418	2,245	1,721
Terminals			
Revenues from external customers	1,789	1,712	1,719
Intersegment revenues	3	3	3
CO_2	1,334	1,009	1,038
Corporate and intersegment eliminations	(30)	(68)	(40)
Total consolidated revenues	$ 19,200	$ 16,610	$ 11,700

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Operating expenses(a)			
Natural Gas Pipelines	$ 8,562	$ 7,000	$ 3,457
Products Pipelines	2,391	1,239	779
Terminals	853	793	762
CO_2	554	289	404
Corporate and intersegment eliminations	(9)	(34)	(4)
Total consolidated operating expenses	$ 12,351	$ 9,287	$ 5,398

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Other expense (income)(b)			
Natural Gas Pipelines	$ (13)	$ 1,597	$ 1,009
Products Pipelines	(12)	—	21
Terminals	(14)	32	(50)
CO_2	(1)	(8)	950
Corporate	1	(4)	—
Total consolidated other expense (income)	$ (39)	$ 1,617	$ 1,930

	Year Ended December 31, 2022	2021	2020
	(In millions)		
DD&A			
Natural Gas Pipelines	$ 1,096	$ 1,099	$ 1,062
Products Pipelines	336	335	347
Terminals	458	440	438
CO_2	272	236	291
Corporate	24	25	26
Total consolidated DD&A	$ 2,186	$ 2,135	$ 2,164

	Year Ended December 31, 2022	2021	2020
	(In millions)		
Earnings from equity investments and amortization of excess cost of equity investments			
Natural Gas Pipelines	$ 650	$ 435	$ 551
Products Pipelines	33	34	45
Terminals	14	15	22
CO_2	31	29	22
Total consolidated equity earnings	$ 728	$ 513	$ 640

	Year Ended December 31, 2022	2021	2020
	(In millions)		
Other, net-income (expense)			
Natural Gas Pipelines	$ (19)	$ 216	$ 11
Products Pipelines	—	1	1
Terminals	8	3	13
Corporate	66	62	31
Total consolidated other, net-income (expense)	$ 55	$ 282	$ 56

	Year Ended December 31, 2022	2021	2020
	(In millions)		
Segment EBDA(c)			
Natural Gas Pipelines	$ 4,801	$ 3,815	$ 3,483
Products Pipelines	1,107	1,064	977
Terminals	975	908	1,045
CO_2	819	760	(292)
Total Segment EBDA	7,702	6,547	5,213
DD&A	(2,186)	(2,135)	(2,164)
Amortization of excess cost of equity investments	(75)	(78)	(140)
General and administrative and corporate charges	(593)	(623)	(653)
Interest, net	(1,513)	(1,492)	(1,595)
Income tax expense	(710)	(369)	(481)
Total consolidated net income	$ 2,625	$ 1,850	$ 180

	Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Capital expenditures			
Natural Gas Pipelines	$ 666	$ 570	$ 945
Products Pipelines	—	122	122
Terminals	552	332	433
CO_2	371	230	186
Corporate	32	27	21
Total consolidated capital expenditures	$ 1,621	$ 1,281	$ 1,707

	December 31,	
	2022	2021
	(In millions)	
Investments		
Natural Gas Pipelines	$ 6,993	$ 6,887
Products Pipelines	445	465
Terminals	128	137
CO_2	87	89
Total consolidated investments	$ 7,653	$ 7,578

	December 31,	
	2022	2021
	(In millions)	
Other intangibles, net		
Natural Gas Pipelines	$ 439	$ 557
Products Pipelines	777	868
Terminals	38	51
CO_2	555	202
Total consolidated other intangibles, net	$ 1,809	$ 1,678

	December 31,	
	2022	2021
	(In millions)	
Assets		
Natural Gas Pipelines	$ 47,978	$ 47,746
Products Pipelines	8,985	9,088
Terminals	8,357	8,513
CO_2	3,449	2,843
Corporate assets(d)	1,309	2,226
Total consolidated assets	$ 70,078	$ 70,416

(a) Includes costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
(b) Includes (gain) loss on divestitures and impairments, net and other income, net.
(c) Includes revenues, earnings from equity investments, and other, net, less operating expenses, (gain) loss on divestitures and impairments, net and other income, net.
(d) Includes cash and cash equivalents, margin and restricted deposits, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy balances) not allocated to our reportable segments.

We do not attribute interest and debt expense to any of our reportable business segments.

Following is geographic information regarding the revenues and long-lived assets of our business:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Revenues from external customers			
U.S.	$ 19,036	$ 16,479	$ 11,625
Mexico and other foreign	164	131	75
Total consolidated revenues from external customers	$ 19,200	$ 16,610	$ 11,700

	December 31,		
	2022	2021	2020
		(In millions)	
Long-term assets, excluding goodwill and other intangibles			
U.S.	$ 44,425	$ 44,916	$ 46,384
Mexico and other foreign	75	78	81
Canada	1	1	1
Total consolidated long-lived assets	$ 44,501	$ 44,995	$ 46,466

17. Leases

Following are components of our lease cost:

	Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Operating leases	$ 62	$ 60	$ 55
Short-term and variable leases	101	109	101
Total lease cost	$ 163	$ 169	$ 156

Other information related to our operating leases are as follows:

	Year Ended December 31,		
	2022	2021	2020
		(In millions, except lease term and discount rate)	
Operating cash flows from operating leases	$ (132)	$ (137)	$ (131)
Investing cash flows from operating leases	(31)	(32)	(25)
ROU assets obtained in exchange for operating lease obligations, net of retirements	22	59	20
Amortization of ROU assets	50	47	46
Weighted average remaining lease term	9.8 years	10.39 years	11.56 years
Weighted average discount rate	4.26 %	3.95 %	4.27 %

Amounts recognized in the accompanying consolidated balance sheets are as follows:

		December 31,	
Lease Activity(a)	Balance sheet location	2022	2021
		(In millions)	
ROU assets	Deferred charges and other assets	$ 287	$ 315
Short-term lease liability	Other current liabilities	47	45
Long-term lease liability	Other long-term liabilities and deferred credits	240	270

(a) We have immaterial financing leases recorded as of December 31, 2022 and 2021.

Operating lease liabilities under non-cancellable leases (excluding short-term leases) as of December 31, 2022 are as follows:

Year	Commitment
	(In millions)
2023	$ 58
2024	50
2025	40
2026	32
2027	29
Thereafter	166
Total lease payments	375
Less: Interest	(88)
Present value of lease liabilities	$ 287

Short-term lease costs are not material to us and are anticipated to be similar to the current year short-term lease expense outlined in this disclosure.

18. Litigation and Environmental

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact to our business. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose the following contingencies where an adverse outcome may be material or, in the judgment of management, we conclude the matter should otherwise be disclosed.

EPNG FERC Proceeding

On April 21, 2022, EPNG was notified by the FERC of the commencement of a rate proceeding against it pursuant to Section 5 of the Natural Gas Act. This proceeding sets the matter for hearing to determine whether EPNG's current rates remain just and reasonable. A proceeding under Section 5 of the Natural Gas Act is prospective in nature such that a change in rates charged to customers, if any, would likely only occur after the FERC has issued a final order. On November 18, 2022, EPNG filed a Stipulation and Agreement (S&A) to establish base rates and rate reductions during the term of the S&A, including a cumulative 16% reduction on average across mainline rate zones, to be phased in over 3 years beginning January 1, 2023, and a rate moratorium until September 30, 2027. FERC approved the S&A without modification on January 31, 2023.

Gulf LNG Facility Disputes

On September 28, 2018, GLNG filed a lawsuit against Eni S.p.A. in the Supreme Court of the State of New York in New York County to enforce a Guarantee Agreement (Guarantee) entered into by Eni S.p.A. on December 10, 2007 in connection with a contemporaneous terminal use agreement entered into by its affiliate, Eni USA Gas Marketing LLC (Eni USA). The suit to enforce the Guarantee against Eni S.p.A. was filed after an arbitration tribunal delivered an award on June 29, 2018 which called for the termination of the terminal use agreement and payment of compensation by Eni USA to GLNG. In response to GLNG's lawsuit to enforce the Guarantee, Eni S.p.A. filed counterclaims based on the terminal use agreement and a parent direct agreement with Gulf LNG Energy (Port), LLC. The foregoing counterclaims asserted by Eni S.p.A seek unspecified damages and involve the same substantive allegations which were dismissed with prejudice in previous separate arbitrations with Eni USA described above and with GLNG's remaining customer Angola LNG Supply Services LLC (ALSS), a consortium of international oil companies including Eni S.p.A. On January 4, 2022, the trial court entered a decision granting Eni S.p.A's motion for summary judgment on the claims asserted by GLNG to enforce the Guarantee. GLNG filed an interlocutory appeal of the decision, which remains pending. Pending resolution of GLNG's appeal and further proceedings in the trial court, the foregoing counterclaims and other claims asserted by Eni S.p.A based on the terminal use agreement and parent direct agreement remain pending in the trial court. We vigorously dispute that the foregoing counterclaims and other claims asserted by Eni S.p.A. have any merit, particularly since they were dismissed with prejudice in previous arbitrations involving both Eni USA and ALSS. We intend to vigorously pursue our appeal to enforce the Guarantee and are seeking summary judgment on any remaining counterclaims or other claims asserted by Eni S.p.A.

Continental Resources, Inc. v. Hiland Partners Holdings, LLC

On December 8, 2017, Continental Resources, Inc. (CLR) filed a lawsuit in Garfield County, Oklahoma state court alleging among other claims that Hiland Partners Holdings, LLC (Hiland Partners) breached a Gas Purchase Agreement, dated November 12, 2010, as amended (GPA), by failing to receive and purchase all of CLR's dedicated gas under the GPA produced in three counties in North Dakota. CLR sought damages in excess of $276 million. While Hiland Partners denied all of the claims asserted in the lawsuit, the parties entered into a confidential settlement agreement on September 14, 2022, including an unconditional release and dismissal of the litigation with prejudice.

Freeport LNG Winter Storm Litigation

On September 13, 2021, Freeport LNG Marketing, LLC (Freeport) filed a lawsuit against Kinder Morgan Texas Pipeline LLC and Kinder Morgan Tejas Pipeline LLC in the 133rd District Court of Harris County, Texas (Case No. 2021-58787) alleging that defendants breached the parties' base contract for sale and purchase of natural gas by failing to repurchase natural gas nominated by Freeport between February 10-22, 2021 during Winter Storm Uri. We deny that we were obligated to repurchase natural gas from Freeport given our declaration of force majeure during the storm and our compliance with emergency orders issued by the Railroad Commission of Texas providing heightened priority for the delivery of gas to human needs customers. Freeport alleges that it is owed approximately $104 million, plus attorney fees and interest. On October 24, 2022, the trial court granted our motion for summary judgment on all of Freeport's claims. On November 21, 2022, Freeport filed a notice of intent to appeal the trial court's decision. We believe that our declaration of force majeure was valid and we intend to vigorously defend this case.

Pension Plan Litigation

On February 22, 2021, Kinder Morgan Retirement Plan A participants Curtis Pedersen and Beverly Leutloff filed a purported class action lawsuit under the Employee Retirement Income Security Act of 1974 (ERISA). The named plaintiffs were hired initially by the ANR Pipeline Company (ANR) in the late 1970s. Following a series of corporate acquisitions, plaintiffs became participants in pension plans sponsored by the Coastal Corporation (Coastal), El Paso Corporation (El Paso) and our company by virtue of our acquisition of El Paso in 2012 and our assumption of certain of El Paso's pension plan obligations. The lawsuit, which was filed initially in federal court in Michigan and then transferred to the U.S. District Court for the Southern District of Texas (Civil Action No. 4:21-3590), alleges that the series of foregoing transactions resulted in changes to plaintiffs' retirement benefits which are now contested on a purported class-wide basis in the lawsuit. The complaint asserts six claims that fall within three primary theories of liability. Claims I, II, and III all seek the same plan modification as to how the plans calculate benefits for former participants in the Coastal plan. These claims challenge plan provisions which are alleged to constitute impermissible "backloading" or "cutback" of benefits. Claims IV and V allege that former participants in the ANR plans should be eligible for unreduced benefits at younger ages than the plans currently provide. Claim VI asserts that actuarial assumptions used to calculate reduced early retirement benefits for current or former ANR employees are outdated and therefore unreasonable. The complaint alleges that the purported class includes over 10,000 individuals. The lawsuit is in the early stages of discovery and no class has been certified. Plaintiffs seek to recover early retirement benefits as well as declaratory and injunctive relief, but have not pleaded, disclosed or otherwise specified a calculation of alleged damages. Accordingly, the extent of our potential liability for past or future benefits, if any, remains to be determined. We believe that none of the claims are valid and intend to vigorously defend this case.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

Arizona Line 2000 Rupture

On August 15, 2021, the 30" EPNG Line 2000 natural gas transmission pipeline ruptured in a rural area in Coolidge, Arizona. The failure resulted in a fire which destroyed a home, resulting in two fatalities and one injury. The National Transportation Safety Board is investigating the incident. EPNG began the process of returning the impacted pipeline segment to service on February 6, 2023. While no litigation is pending at this time, we notified our insurers of the incident and do not expect that the resolution of claims will have a material adverse impact to our business.

General

As of December 31, 2022 and 2021, our total reserve for legal matters was $70 million and $231 million, respectively.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to local, state and federal laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments could result in substantial costs and liabilities to us, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations.

We are currently involved in several governmental proceedings involving alleged violations of local, state and federal environmental and safety regulations. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties will be material to our business, individually or in the aggregate. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under state or federal administrative orders or related remediation programs. We have established a reserve to address the costs associated with the remediation efforts.

In addition, we are involved with and have been identified as a potentially responsible party (PRP) in several federal and state Superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, crude oil, NGL, natural gas or CO_2, including natural resource damage (NRD) claims.

PHMSA Enforcement Matter for KMLT Midwest Terminals

On July 11, 2022, Kinder Morgan Liquid Terminals (KMLT) received a Notice of Probable Violation (NOPV) from PHMSA relating to inspections conducted during 2021 at KMLT's Cincinnati, Indianapolis, Dayton, Argo, O'Hare, and Wood River Terminals. The NOPV alleged violations of Department of Transportation regulations, proposed a penalty of approximately $455,000 and sought a compliance agreement relating to certain of the alleged violations. On February 3, 2023, PHMSA and KMLT entered into a Consent Agreement resolving the allegations in the NOPV. Also on February 3, 2023, PHMSA issued a Consent Order approving the Consent Agreement. We do not anticipate the costs to resolve this matter, including any costs to implement the Consent Agreement, will have a material adverse impact to our business.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

On January 6, 2017, the EPA issued a Record of Decision (ROD) that established a final remedy and cleanup plan for an industrialized area on the lower reach of the Willamette River commonly referred to as the Portland Harbor Superfund Site (PHSS). The cost for the final remedy is estimated to be more than $2.8 billion and active cleanup is expected to take more than 10 years to complete. KMLT, KMBT, and some 90 other PRPs identified by the EPA are involved in a non-judicial allocation process to determine each party's respective share of the cleanup costs related to the final remedy set forth by the ROD. We are participating in the allocation process on behalf of KMLT (in connection with its ownership or operation of two facilities) and KMBT (in connection with its ownership or operation of two facilities). Effective January 31, 2020, KMLT entered into separate Administrative Settlement Agreements and Orders on Consent (ASAOC) to complete remedial design for two distinct areas within the PHSS associated with KMLT's facilities. The ASAOC obligates KMLT to pay a share of the remedial design costs for cleanup activities related to these two areas as required by the ROD. Our share of responsibility for the PHSS costs will not be determined until the ongoing non-judicial allocation process is concluded or a lawsuit is filed that results in a judicial decision allocating responsibility. At this time we anticipate the non-judicial allocation process will be complete in or around December 2024. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the PHSS. Because costs associated with any remedial plan are expected to be spread over at least several years, we do not anticipate that our share of the costs of the remediation will have a material adverse impact to our business.

In addition to CERCLA cleanup costs, we are reviewing and will attempt to settle, if possible, NRD claims in the amount of approximately $5 million asserted by state and federal trustees following their natural resource assessment of the PHSS.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, New Jersey

EPEC Polymers, Inc. and EPEC Oil Company Liquidating Trust (collectively EPEC) are identified as PRPs in an administrative action under CERCLA known as the Lower Passaic River Study Area (Site) concerning the lower 17-mile stretch of the Passaic River in New Jersey. On March 4, 2016, the EPA issued a Record of Decision (ROD) for the lower eight miles of the Site. At that time the cleanup plan in the ROD was estimated to cost $1.7 billion. The cleanup is expected to take at least six years to complete once it begins. In addition, the EPA and numerous PRPs, including EPEC, engaged in an allocation process for the implementation of the remedy for the lower eight miles of the Site. That process was completed December 28, 2020 and certain PRPs, including EPEC, engaged in discussions with the EPA as a result thereof. On October 4, 2021, the EPA issued a ROD for the upper nine miles of the Site. At that time, the cleanup plan in the ROD was estimated to cost $440 million. No timeline for the cleanup has been established. On December 16, 2022, the United States Department of Justice (DOJ) and EPA announced a settlement and proposed consent decree with 85 PRPs, including EPEC, to resolve their collective liability at the Site. The total amount of the settlement is $150 million. Also on December 16, 2022, the DOJ on behalf of the EPA filed a Complaint against the 85 PRPs, including EPEC, a Notice of Lodging of Consent Decree, and a Consent Decree in the U.S. District Court for the District of New Jersey. We believe our share of the costs to resolve this matter, including our share of the settlement with EPA and the costs to remediate the Site, if any, will not have a material adverse impact to our business.

Louisiana Governmental Coastal Zone Erosion Litigation

Beginning in 2013, several parishes in Louisiana and the City of New Orleans filed separate lawsuits in state district courts in Louisiana against a number of oil and gas companies, including TGP and SNG. In these cases, the parishes and New Orleans, as Plaintiffs, allege that certain of the defendants' oil and gas exploration, production and transportation operations were conducted in violation of the State and Local Coastal Resources Management Act of 1978, as amended (SLCRMA) and that those operations caused substantial damage to the coastal waters of Louisiana and nearby lands. The Plaintiffs seek, among other relief, unspecified money damages, attorneys' fees, interest, and payment of costs necessary to restore the affected areas. There are more than 40 of these cases pending in Louisiana against oil and gas companies, one of which is against TGP and one of which is against SNG, both described further below.

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana against TGP and 17 other energy companies, alleging that the defendants' operations in Plaquemines Parish violated SLCRMA and Louisiana law, and caused substantial damage to the coastal waters and nearby lands. Plaquemines Parish seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected areas. In December 2013, the case was removed to the U.S. District Court for the Eastern District of Louisiana. In April 2015, the U.S. District Court ordered the case to be remanded to the state district court for Plaquemines Parish. In May 2018, the case was removed for a second time to the U.S. District Court. In May 2019, the U.S. District Court ordered the case to be remanded to the state district court. The case has been effectively stayed pending the resolution of jurisdictional issues in separate, consolidated cases to which TGP is not a party; The Parish of Plaquemines, et al. vs. Chevron USA, Inc. et al. consolidated with The Parish of Cameron, et al. v. BP America Production Company, et al. Those cases were removed to federal court and ordered to be remanded to the state district courts for Plaquemines and Cameron Parishes, respectively. The defendants to those consolidated cases pursued an appeal of the remand decisions to the U.S. Court of Appeals for the Fifth Circuit to determine whether there is federal officer jurisdiction. On October 17, 2022, the U.S. Court of Appeals ordered those consolidated cases to be remanded to the state district courts. On November 14, 2022, the defendants to those consolidated cases filed separate Petitions for Panel Rehearing, and for Rehearing En Banc. On November 29, 2022, the U.S. Court of Appeals denied both Petitions. On December 15, 2022, the case against TGP was remanded to the state district court. On January 30, 2023, the defendants to those consolidated cases filed a Petition for Writ of Certiorari with the U.S. Supreme Court seeking review of the decisions of the U.S. Court of Appeals. At this time, we are not able to reasonably estimate the extent of our potential liability, if any. We intend to vigorously defend this case.

On March 29, 2019, the City of New Orleans and Orleans Parish (collectively, Orleans) filed a petition for damages in the state district court for Orleans Parish, Louisiana against SNG and 10 other energy companies alleging that the defendants' operations in Orleans Parish violated the SLCRMA and Louisiana law, and caused substantial damage to the coastal waters and nearby lands. Orleans seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected areas. In April 2019, the case was removed to the U.S. District Court for the Eastern District of Louisiana. In May 2019, Orleans moved to remand the case to the state district court. In January 2020, the U.S. District Court ordered the case to be stayed and administratively closed pending the resolution of issues in a separate case to which SNG is not a party; *Parish of Cameron vs. Auster Oil & Gas, Inc.*, pending in U.S. District Court for the Western District of Louisiana; after which either party may move to re-open the case. On January 23, 2023, the City of New Orleans filed an Ex parte Motion to Reopen Case and Notice of Supplemental Authority asking the U.S. District Court to re-open the case. Until these and other issues are determined, we are not able to reasonably estimate the extent of our potential liability, if any. We intend to vigorously defend this case.

Products Pipeline Incident, Walnut Creek, California

On November 20, 2020, SFPP identified an issue on its Line Section 16 (LS-16) which transports petroleum products in California from Concord to San Jose. We shut down the pipeline and notified the appropriate regulatory agencies of a "threatened release" of gasoline. We investigated the issue over the next several days and on November 24, 2020, identified a crack in the pipeline and notified the regulatory agencies of a "confirmed release." The damaged section of the pipeline was removed and replaced, and the pipeline resumed operations on November 26, 2020. We reported the estimated volume of gasoline released to be 8.1 Bbl. On December 2, 2020, complaints of gasoline odors were reported along the LS-16 pipeline corridor in Walnut Creek. A unified response was implemented by us along with the EPA, the California Office of Spill Prevention and Response, the California Fire Marshall, and the San Francisco Regional Water Quality Control Board. On December 8, 2020, we reported an updated estimated spill volume of up to 1,000 Bbl.

On October 28, 2021, we were informed by the California Attorney General it was contemplating criminal charges against us asserting the November 2020 discharge of gasoline affected waters of the State of California, and there was a failure to make timely notices of this discharge to appropriate state agencies. On December 16, 2021, we entered into a plea agreement with the State of California to resolve misdemeanor charges of the unintentional, non-negligent discharge of gasoline resulting from the release and the claimed failure to provide timely notices of the discharge to appropriate state agencies. Under the plea agreement, SFPP plead no-contest to two misdemeanors and paid approximately $2.5 million in fines, penalties, restitution, environmental improvement project funding, and for enforcement training in the State of California, and was placed on informal, unsupervised probation for a term of 18 months.

Since the November 2020 release, we have cooperated fully with federal and state agencies and have worked diligently to remediate the affected areas. We anticipate civil enforcement actions by federal and state agencies arising from the November 2020 release as well as ongoing monitoring and, where necessary, remediation under the oversight of the San Francisco Regional Water Quality Control Board until site conditions demonstrate no further actions are required. We do not anticipate the costs to resolve those enforcement matters, including the costs to monitor and further remediate the site, will have a material adverse impact to our business.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business. As of December 31, 2022 and 2021, we have accrued a total reserve for environmental liabilities in the amount of

$221 million and $243 million, respectively. In addition, as of both December 31, 2022 and 2021, we had recorded a receivable of $12 million for expected cost recoveries that have been deemed probable.

19. Recent Accounting Pronouncements

Accounting Standards Updates

Reference Rate Reform (Topic 848)

On March 12, 2020, the FASB issued ASU No. 2020-04, "*Reference Rate Reform – Facilitation of the Effects of Reference Rate Reform on Financial Reporting.*" This ASU provides temporary optional expedients and exceptions to GAAP guidance on contract modifications and hedge accounting to ease the financial reporting burdens of the expected market transition from LIBOR and other interbank offered rates to alternative reference rates, such as the SOFR. Entities can elect not to apply certain modification accounting requirements to contracts affected by reference rate reform, if certain criteria are met. An entity that makes this election would not have to remeasure the contracts at the modification date or reassess a previous accounting determination. Entities can also elect various optional expedients that would allow them to continue applying hedge accounting for hedging relationships affected by reference rate reform, if certain criteria are met.

On January 7, 2021, the FASB issued ASU No. 2021-01, "*Reference Rate Reform (Topic 848): Scope.*" This ASU clarifies that all derivative instruments affected by changes to the interest rates used for discounting, margining or contract price alignment (the "Discounting Transition") are in the scope of Topic 848 and therefore qualify for the available temporary optional expedients and exceptions. As such, entities that employ derivatives that are the designated hedged item in a hedge relationship where perfect effectiveness is assumed can continue to apply hedge accounting without de-designating the hedging relationship to the extent such derivatives are impacted by the Discounting Transition.

On December 21, 2022, the FASB issued ASU No. 2022-06, "*Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848.*" This ASU defers the sunset date of Topic 848 from December 31, 2022, to December 31, 2024, after which entities will no longer be permitted to apply the optional expedients and exceptions in Topic 848.

The guidance was effective upon issuance.

During the year ended December 31, 2022 we amended certain of our existing fixed-to-variable interest rate swap agreements, which were designated as fair value hedges, to transition the variable leg of such agreements from LIBOR to SOFR. These agreements contain a combined notional principal amount of $4,425 million and convert a portion of our fixed rate debt to variable rates through March 2035. Concurrent with these amendments, we elected certain of the optional expedients provided in Topic 848 which allow us to maintain our prior designation of fair value hedge accounting to these agreements. As we continue to amend our interest rate swap agreements to transition from LIBOR to SOFR, we will assess whether such amendments qualify for any of the optional expedients in Topic 848 and, should they qualify, whether we wish to elect any such optional expedients. See Note 14 "Risk Management—*Interest Rate Risk Management*" for more information on our interest rate risk management activities.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.*

None.

Item 9A. *Controls and Procedures.*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2022, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2022 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.***

Not Applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023.

Item 11. ***Executive Compensation.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2023.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) Documents Filed as Part of the Report

(1) Financial Statements

See Part II, Item 8. "*Financial Statements and Supplementary Data*—Index to Financial Statements" set forth on Page 68.

(2) Financial Statement Schedules

Financial statement schedules are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description
3.1 *	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081)).
3.2 *	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K, filed January 24, 2023 (File No. 001-35081)).
4.1 *	Form of certificate representing Class P common stock of KMI (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773)).
4.2 *	Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081)).
4.3 *	Amendment No. 1 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.3 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081)).
4.4 *	Amendment No. 2 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on December 3, 2014 (File No. 001-35081)).
4.5 *	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446)).
4.6 *	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446)).
4.7 *	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234)).
4.8 *	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234)).
4.9 *	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234)).
4.10 *	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234)).
4.11 *	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234)).
4.12 *	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346)).

4.13 *	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346)).
4.14 *	Form of 7.30% Notes due 2033 (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346)).
4.15 *	Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961)).
4.16 *	Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961)).
4.17 *	Certificate of the Vice President, Treasurer and Chief Financial Officer and the Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234)).
4.18 *	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234)).
4.19 *	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234)).
4.20 *	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234)).
4.21 *	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234)).
4.22 *	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234)).
4.23 *	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234)).
4.24 *	Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 1-11234)).
4.25 *	Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234)).
4.26 *	Indenture, dated March 1, 2012, between KMI and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-3 filed on March 1, 2012 (File No. 001-35081)).

4.27 *	Certificate of the Vice President and Treasurer and the Vice President and Secretary of KMI establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045 (filed as Exhibit 10.53 to KMI's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-35081)).
4.28 *	Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 5.050% Senior Notes due 2046 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 (File No. 001-35081)).
4.29 *	Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 1.500% Senior Notes due 2022 and 2.250% Senior Notes due 2027 (filed as Exhibit 4.2 to KMI's Form 8-A, filed March 16, 2015 (File No. 001-35081)).
4.30 *	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 3.150% Senior Notes due January 15, 2023 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081)).
4.31 *	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the Floating Rate Senior Notes due January 15, 2023 (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081)).
4.32 *	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 4.300% Senior Notes due 2028 and the 5.200% Senior Notes due 2048 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 (File No. 001-35081)).
4.33 *	Certificate of the Vice President and Chief Financial Officer, and Vice President, Investor Relations and Treasurer of KMI establishing the terms of the 2.00% Notes due February 15, 2031 and the 3.25% Notes due August 1, 2050 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020 (File No. 001-35081)).
4.34 *	Certificate of the Vice President and Chief Financial Officer, and Vice President, Investor Relations and Treasurer of KMI establishing the terms of the 3.60% Notes due February 15, 2051 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021 (File No. 001-35081)).
4.35 *	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of KMI establishing the terms of the 1.750% Notes due 2026 (filed as Exhibit 4.35 to KMI's Annual Report on Form 10-K for the year ended December 31, 2021 (File No. 001-35081)).
4.36 *	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 4.800% Senior Notes due 2033 and the 5.450% Senior Notes due 2052 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2022 (File No. 001-35081)).
4.37	Certain instruments with respect to long-term debt of KMI and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of KMI and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. KMI hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
4.38 *	Description of Capital Stock of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (filed as Exhibit 4.37 to KMI's Annual Report on Form 10-K for the year ended December 31, 2019 (File No. 001-35081)).
4.39 *	Description of Debt Securities of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (filed as Exhibit 4.38 to KMI's Annual Report on Form 10-K for the year ended December 31, 2019 (File No. 001-35081)).
10.1 *	Kinder Morgan, Inc. 2021 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to Post-Effective Amendment No. 1 to KMI's Registration Statement on Form S-8 filed July 16, 2021 (File No. 333-205430)).
10.2 *	2021 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 (File No. 001-35081)).
10.3 *	2016 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-35081))
10.4 *	2018 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (File No. 001-35081))
10.5 *	Kinder Morgan, Inc. Second Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.4 to KMI's Form 10-Q for the quarter ended September 30, 2021 (File No. 001-35081)).
10.6 *	2021 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.5 to KMI's Form 10-Q for the quarter ended September 30, 2021 (File No. 001-35081)).

10.7 *	KMI Employees Stock Purchase Plan (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081)).
10.8 *	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed January 26, 2021 (File No. 001-35081)).
10.9 *	Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.15 to KMI's Annual Report on Form 10-K for the year ended December 31, 2018 (File No. 001-35081)).
10.10 *	Revolving Credit Agreement, dated August 20, 2021 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed August 25, 2021 (File No. 001-35081)).
10.11 *	First Amendment dated August 20, 2021 to Revolving Credit Agreement dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed August 25, 2021 (File 001-35081)).
10.12	First Amendment dated December 15, 2022 to Revolving Credit Agreement dated August 20, 2021 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto.
10.13	Second Amendment, dated December 15, 2022, to Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto.
10.14	Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2022.
21.1	Subsidiaries of KMI.
22.1	Subsidiary guarantors and issuers of guaranteed securities.
23.1	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive data files pursuant to Rule 405 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language): (i) our Consolidated Statements of Income for the years ended December 31, 2022, 2021, and 2020; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2022, 2021, and 2020; (iii) our Consolidated Balance Sheets as of December 31, 2022 and 2021; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021, and 2020; (v) our Consolidated Statements of Stockholders' Equity as of and for the years ended December 31, 2022, 2021, and 2020; and (vi) the notes to our Consolidated Financial Statements.
104	Cover Page Interactive Data File pursuant to Rule 406 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language) and contained in Exhibit 101.

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

Item 16. *Form 10-K Summary.*

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

/s/ David P. Michels

David P. Michels
Vice President and Chief Financial Officer

Date: February 8, 2023

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAVID P. MICHELS David P. Michels	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 8, 2023
/s/ STEVEN J. KEAN Steven J. Kean	Chief Executive Officer (principal executive officer); Director	February 8, 2023
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 8, 2023
/s/ KIMBERLY A. DANG Kimberly A. Dang	President; Director	February 8, 2023
/s/ TED A. GARDNER Ted A. Gardner	Director	February 8, 2023
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 8, 2023
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 8, 2023
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 8, 2023
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 8, 2023
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 8, 2023
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 8, 2023
/s/ C. PARK SHAPER C. Park Shaper	Director	February 8, 2023
/s/ WILLIAM A. SMITH William A. Smith	Director	February 8, 2023
/s/ JOEL V. STAFF Joel V. Staff	Director	February 8, 2023
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 8, 2023
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 8, 2023