

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

Form 10-K

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

For the fiscal year ended December 31, 2019

or

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

For the transition period from _____ to _____

Commission file number: 001-35081



Kinder Morgan, Inc.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

80-0682103

(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:

<u>Title of each class</u>	<u>Trading Symbol(s)</u>	<u>Name of each exchange on which registered</u>
Class P Common Stock	KMI	New York Stock Exchange
1.500% Senior Notes due 2022	KMI 22	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," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 28, 2019 was approximately \$40,707,308,596. As of February 7, 2020, the registrant had 2,265,063,459 Class P shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2020 Annual Meeting of Stockholders, which shall be filed no later than April 29, 2020, 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.	KMTP	= Kinder Morgan Texas Pipeline LLC
EagleHawk	= EagleHawk Field Services LLC	MEP	= Midcontinent Express Pipeline LLC
Elba Express	= Elba Express Company, L.L.C.	NGPL	= Natural Gas Pipeline Company of America LLC
EIG	= EIG Global Energy Partners	Ruby	= Ruby Pipeline Holding Company, L.L.C.
ELC	= Elba Liquefaction Company, L.L.C.	SFPP	= SFPP, L.P.
EPNG	= El Paso Natural Gas Company, L.L.C.	SLNG	= Southern LNG Company, L.L.C.
FEP	= Fayetteville Express Pipeline LLC	SNG	= Southern Natural Gas Company, L.L.C.
Hiland	= Hiland Partners, LP	TGP	= Tennessee Gas Pipeline Company, L.L.C.
KinderHawk	= KinderHawk Field Services LLC	TMEP	= Trans Mountain Expansion Project
KMBT	= Kinder Morgan Bulk Terminals, Inc.	TMPL	= Trans Mountain Pipeline System
KMGP	= Kinder Morgan G.P., Inc.	Trans Mountain	= Trans Mountain Pipeline ULC
KMI	= Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries	WIC	= Wyoming Interstate Company, L.L.C.
KML	= Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries	WYCO	= WYCO Development L.L.C.
KMLP	= Kinder Morgan Louisiana Pipeline LLC		

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

2017 Tax Reform	= The Tax Cuts & Jobs Act of 2017	GAAP	= United States Generally Accepted Accounting Principles
/d	= per day	IPO	= Initial Public Offering
AFUDC	= allowance for funds used during construction	LIBOR	= London Interbank Offered Rate
BBtu	= billion British Thermal Units	LLC	= limited liability company
Bcf	= billion cubic feet	LNG	= liquefied natural gas
CERCLA	= Comprehensive Environmental Response, Compensation and Liability Act	MBbl	= thousand barrels
C\$	= Canadian dollars	MMBbl	= million barrels
CO ₂	= carbon dioxide or our CO ₂ business segment	MMtons	= million tons
CPUC	= California Public Utilities Commission	NEB	= Canadian National Energy Board
DCF	= distributable cash flow	NGL	= natural gas liquids
DD&A	= depreciation, depletion and amortization	NYMEX	= New York Mercantile Exchange
Dth	= dekatherms	NYSE	= New York Stock Exchange
EBDA	= earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	OTC	= over-the-counter
EBITDA	= earnings before interest, income taxes, depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments	PHMSA	= United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
EPA	= United States Environmental Protection Agency	ROU	= Right-of-Use
FASB	= Financial Accounting Standards Board	SEC	= United States Securities and Exchange Commission
FERC	= Federal Energy Regulatory Commission	TBtu	= trillion British Thermal Units
		U.S.	= United States of America
		WTI	= West Texas Intermediate

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

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 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, CO₂, 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;
- 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, petrochemical or chemical 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, Oklahoma, Ohio, 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 CO₂ 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 of 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 fluctuations in interest rates;
- political and economic instability of the oil 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 CO₂ 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 forward-looking statements.

Additional discussion of factors that may affect our forward-looking statements appears 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*." In addition, there is a general level of uncertainty regarding the extent to which potential positive or negative changes to fiscal, tax and trade policies may impact us and those with whom we do business. It is not possible at this time to predict the extent of any such impact. When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. These factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, and described below under Items 1 and 2 "*Business and Properties—General Development of Business—2020 Outlook*," to update the above list or

to announce publicly the result of any revisions to 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 and 147 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO₂ and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke.

General Development of Business

Organizational Structure

We are a Delaware corporation and our common stock has been publicly traded since February 2011.

You should read the following in conjunction with our accompanying consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our accompanying consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000.

Recent Developments

The following is a brief listing of significant developments and updates related to our major projects and other transactions. Additional information regarding most of these items may be found elsewhere in this report. "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)
Divestitures			
U.S. Portion of Cochin Pipeline and KML	Sold the U.S. portion of the Cochin Pipeline to Pembina Pipeline Corporation (Pembina). In addition, Pembina acquired all of the outstanding common equity of KML, including our 70% interest.	Completed in December 2019. Total pre-tax consideration received of \$2.5 billion, including cash proceeds from shares of Pembina sold in January 2020.	n/a
Placed in service			
Gulf Coast Express Pipeline Project (GCX Project)	Joint venture pipeline project (KMTP 34%, DCP GCX Pipeline LLC 25%, Targa GCX Pipeline LLC 25% and Altus Midstream Processing LP 16% ownership interest) to provide up to 2.0 Bcf/d of transportation capacity from the Permian Basin to the Agua Dulce, Texas area. Subscribed under long-term firm transportation contracts.	The first 9 miles of the Midland Lateral were placed in service in August 2018 and the remaining 40 miles were placed in service in April 2019. Project was placed in full commercial operations in September 2019. Total pipeline miles for the completed project is 520 miles.	\$616 million

Asset or project	Description	Activity	Approx. Capital Scope (KMI Share)
Texas Intrastate Crossover Expansion	Expansion project that provides over 1,000,000 Dth/d of transportation capacity from the Katy Hub, the Company's Houston Central processing plant, and other third-party receipt points to serve customers in Texas and Mexico. Phase I is supported by long-term firm transportation contracts of nearly 700,000 Dth/d, including a contract with Comisión Federal de Electricidad. Phase 2, which is supported by long-term firm transportation contracts with Cheniere Energy, Inc. at its Corpus Christi LNG facility and SK E&S LNG, LLC, provides service to the Freeport LNG export facility and other domestic markets.	Phase 1 and Phase 2 are in service.	\$288 million
Other Announcements			
Natural Gas Pipelines			
ELC and SLNG Expansion	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Georgia, with a total capacity of 2.5 MMtons per year of LNG, equivalent to approximately 357,000 Dth/d of natural gas. Supported by a long-term firm contract with Shell.	SLNG facilities and the first of 10 liquefaction units were placed in service in September 2019, with two additional units in the fourth quarter 2019, and one unit in January 2020. The remaining six units are expected to be placed in service by mid-2020.	\$1.2 billion
Permian Highway Pipeline Project (PHP Project)	Joint venture pipeline project (KMTP 26.67%, BCP PHP, LLC (BCP) 26.67%, Altus Midstream Processing LP 26.67% and an affiliate of an anchor shipper has a 20% ownership interest) is designed to transport up to 2.1 Bcf/d of natural gas through approximately 430 miles of 42-inch pipeline from the Waha, Texas area to the U.S. Gulf Coast and Mexico markets. Subscribed under long-term firm transportation contracts.	Expected in-service date is early 2021.	\$600 million
TGP East 300 Upgrade	Expansion project involves upgrading compression facilities upstream on TGP's system in order to provide 110,000 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 2022, pending regulatory approvals.	\$246 million
KMLP Acadiana Expansion	Expansion project that will provide 945,000 Dth/d of capacity to serve Train 6 at Cheniere's Sabine pass LNG terminal. Project supported by long-term contracts.	Expected to be placed in service by the second quarter 2022, pending regulatory approvals.	\$145 million
EPNG South Mainline Expansion	Expansion project that provides 471,000 Dth/d of firm transportation capacity with a first phase of system improvements to deliver volumes to the Sierrita pipeline and the second phase for incremental deliveries of natural gas to Arizona and California. Subscribed under long-term firm transportation contracts.	Phase 1 is already in service. Phase 2 is expected to be in service by the third quarter 2020.	\$141 million
NGPL Gulf Coast Southbound Expansion (second phase)	Expansion project to increase southbound capacity on NGPL's Gulf Coast System by approximately 300,000 Dth/d to serve Corpus Christi Liquefaction. Subscribed under a long-term firm transportation contract.	Expected in-service date is the first half of 2021, pending regulatory approvals.	\$114 million

n/a - not applicable

Financings

During 2019, we repaid approximately \$2.8 billion of maturing debt with cash proceeds received from the sales of TMPL and the U.S. portion of the Cochin Pipeline. After-tax proceeds received in January 2020 from the sale of Pembina stock received from the sale of KML will be used to pay down debt in early 2020.

2020 Outlook

We expect to declare dividends of \$1.25 per share for 2020, a 25% increase from the 2019 declared dividends of \$1.00 per share, generate approximately \$5.1 billion of DCF, or \$2.24 of DCF per share, and \$7.6 billion of Adjusted EBITDA. We also expect to invest \$2.4 billion in expansion projects and contributions to joint ventures during 2020. Our discretionary spending will be primarily funded with excess, internally generated cash flow, with no need to access equity markets during 2020. We expect that our Net Debt-to-Adjusted EBITDA ratio for 2020 year-end will be 4.3 times. See Item 7 “*Management’s Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures.*”

We do not provide budgeted net income attributable to common stockholders or budgeted net income, the GAAP financial measures most directly comparable to the non-GAAP financial measures of DCF and Adjusted EBITDA, respectively, due to the impracticality of quantifying certain components required by GAAP such as: unrealized gains and losses on derivatives marked to market and potential changes in estimates for certain contingent liabilities.

Our expectations for 2020 assume average annual prices for WTI crude oil and Henry Hub natural gas of \$55.00 per barrel and \$2.50 per MMBtu, respectively, consistent with the forward pricing during our 2020 budget process. The vast majority of revenue we generate is supported by multi-year fee-based customer arrangements and therefore is not directly exposed to commodity prices. The primary area where we have direct commodity price sensitivity is in our CO₂ segment, in which we hedge the majority of the next 12 months of oil and NGL production to minimize this sensitivity. For 2020, we estimate that every \$1 change in the average WTI crude oil price per barrel would impact our DCF by approximately \$5 million, each \$0.10 per MMBtu change in the average price of natural gas would impact DCF by approximately \$1 million, and each 1% change in the ratio of the weighted average NGL price per barrel to the average WTI crude oil price per barrel would impact DCF by approximately \$2 million.

In addition, our expectations for 2020 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*” below and “*Information Regarding Forward-Looking Statements*” at the beginning of this report for more information. Furthermore, we plan to provide updates to our 2020 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

Financial Information about Segments

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

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 of growing markets within North America;
- 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 expansions of assets 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 full and partial 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

Natural Gas Pipelines

Our Natural Gas Pipelines business segment includes interstate and intrastate pipelines, underground storage facilities and our LNG liquefaction and terminal 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 26,000 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., Louisiana, Texas, Northeast, Rocky Mountain, Midwest and Southeastern 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, 2019. The design capacity represents transmission, gathering, regasification or liquefaction capacity, depending on the nature of the asset.

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
North Region				
TGP	11,775	12.12	80	Marcellus, Utica, Gulf Coast, Haynesville, and Eagle Ford shale supply basins; Northeast, Southeast, Gulf Coast and U.S.-Mexico border markets
NGPL (50%)	9,100	7.60	288	Chicago and other Midwest markets and all central U.S. supply basins; north to south deliveries, including deliveries to LNG facilities and to the U.S.-Mexico border markets
KMLP	135	3.00	—	Columbia Gulf, ANR Pipeline Company and various other pipeline interconnects; Cheniere Sabine Pass LNG and industrial markets
South Region				
SNG (50%)	6,930	4.40	66	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee markets; basins in Texas, Oklahoma, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus) (50%)	5,360	3.90	—	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
MEP (50%)	515	1.80	—	Oklahoma and north Texas supply with interconnects to Transco, Columbia Gulf, SNG and various other pipelines
Elba Express	190	1.10	—	South Carolina to Georgia; connects to SNG, Transco, SLNG, ELC and Dominion Energy Carolina Gas Transmission
FEP (50%)	185	2.00	—	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission and ANR Pipeline Company
Gulf LNG Holdings (50%)	5	1.50	7	Near Pascagoula, Mississippi; connects to four interstate pipelines and a natural gas processing plant
Bear Creek Storage (75%)	—	—	59	Located in Louisiana; provides storage capacity to SNG and TGP
SLNG	—	1.76	12	Located on Elba Island in Georgia; connects to Elba Express, SNG and Dominion Energy Carolina Gas Transmission
ELC (51%)	—	0.35	—	Located on Elba Island; connects to Elba Express delivering to SLNG for LNG storage and ship loading; first of 10 liquefaction units placed in service September 2019. Two additional units placed in service in fourth quarter 2019.

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
West Region				
EPNG/Mojave	10,665	6.38	44	Permian, San Juan and Anadarko Basins; interconnects and demand locations in California, Arizona, New Mexico, Texas, Oklahoma and Mexico
CIG	4,290	6.00	38	Rocky Mountain and Anadarko Basins; interconnects and demand locations in Colorado, Wyoming, Utah, Montana, Kansas, Oklahoma and Texas
WIC	850	3.61	—	Rocky Mountain Basins; interconnects and demand locations in Colorado, Utah and Wyoming
Ruby (50%)(a)	685	1.53	—	Rocky Mountain Basins; interconnects and demand locations in Utah, Nevada, Oregon and California
CPGPL	415	1.20	—	Rocky Mountain Basins; interconnects and demand locations in Colorado and Kansas
TransColorado	310	0.80	—	San Juan, Permian, Paradox and Piceance Basins; interconnects and demand locations in Colorado and New Mexico
WYCO (50%)	225	1.20	7	Denver Julesburg Basin; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCO's pipeline systems
Sierrita (35%)	60	0.20	—	Connects with EPNG near Tucson, Arizona, to the U.S.-Mexico international border crossing near Sasabe, Arizona to supply a third-party natural gas pipeline in Mexico
Young Gas Storage (48%)	15	—	6	Located in Morgan County, Colorado in the Denver Julesburg Basin; capacity is committed to CIG and Colorado Springs Utilities
Keystone Gas Storage	15	—	6	Located in the Permian Basin near the Waha natural gas trading hub in West Texas
Midstream				
KM Texas and Tejas pipelines(b)	5,845	7.80	132 [0.51]	Texas Gulf Coast supply and markets
Mier-Monterrey pipeline(b)	90	0.65	—	Starr County, Texas to Monterrey, Mexico; connects to CENEGAS national system and multiple power plants in Monterrey
KM North Texas pipeline(b)	80	0.33	—	Interconnect from NGPL; connects to a 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Gulf Coast Express pipeline (34%)	520	2.00	—	Permian Basin to the Agua Dulce, Texas area
Oklahoma				
Oklahoma system	4,035	0.73	[0.13]	Hunton Dewatering, Woodford Shale, Anadarko Basin and Mississippi Lime, Arkoma Basin
Cedar Cove (70%)	115	0.03	—	Oklahoma STACK, capacity excludes third-party offloads
South Texas				
South Texas system	1,180	1.93	[1.02]	Eagle Ford shale, Woodbine and Eaglebine formations
Webb/Duval gas gathering system (63%)	145	0.15	—	South Texas
Camino Real	75	0.15	—	South Texas, Eagle Ford shale formation
EagleHawk (25%)	530	1.20	—	South Texas, Eagle Ford shale formation
KM Altamont	1,460	0.1	[0.10]	Utah, Uinta Basin
Red Cedar (49%)	900	0.33	—	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union (42.595%)	315	1.25	—	Powder River Basin (Wyoming)
Bighorn (51%)	290	0.60	—	Powder River Basin (Wyoming)
KinderHawk	520	2.35	—	Northwest Louisiana, Haynesville and Bossier shale formations

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
North Texas	545	0.14	[0.10]	North Barnett Shale Combo
KM Treating	—	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
Hiland - Williston - gas	2,065	0.62	[0.33]	Bakken/Three Forks shale formations - natural gas gathering and processing
		(MBbl/d)	(MBbl)	
Liquids/Condensate Pipelines				
Liberty pipeline (50%)	85	140	—	Y-grade pipeline from Houston Central complex to the Texas Gulf Coast
South Texas NGL pipelines	340	115	—	Ethane and propane pipelines from Houston Central complex to the Texas Gulf Coast
Utopia pipeline (50%)	265	50	—	Harrison County, Ohio extending to Windsor, Ontario
Cypress pipeline (50%)	105	56	—	Mont Belvieu, Texas to Lake Charles, Louisiana
EagleHawk - Condensate (25%)	400	220	60	South Texas, Eagle Ford shale formation

- (a) We operate Ruby and own the common interest in Ruby. Pembina owns the remaining interest in Ruby in the form of a convertible preferred interest and has 50% voting rights. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby.
- (b) Collectively referred to as Texas intrastate natural gas pipeline operations.

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 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 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 renewables such as wind and solar, oil, coal and nuclear. 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, 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, 2019:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity(MMBbl)	Supply and Market Region
Crude & Condensate				
KM Crude & Condensate pipeline	264	5	2.6	Eagle Ford shale field in South Texas (Dewitt, Karnes, and Gonzales Counties) to the Houston ship channel refining complex
Camino Real Gathering	68	1	0.1	South Texas, Eagle Ford shale formation
Hiland - Williston Basin - oil(b)	1,595	7	0.9	Bakken/Three Forks shale formations - crude oil gathering and transporting
Double H pipeline(b)	512	—	—	Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Double Eagle pipeline (50%)	204	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
KM Condensate Processing Facility (KMCC - Splitter)	—	1	2.0	Houston Ship Channel, Galena Park, Texas
Southeast Refined Products				
Plantation pipeline (51%)	3,182	—	—	Louisiana to Washington D.C.
Central Florida pipeline	206	2	2.5	Tampa to Orlando
Southeast Terminals	—	25	8.9	From Mississippi through Virginia, including Tennessee
Transmix Operations	—	5	0.6	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; St. Louis, Missouri; and Greensboro, North Carolina
West Coast Refined Products				
Pacific (SFPP) (99.5%)	2,845	13	15.1	Six western states
Calnev	566	2	2.0	Colton, California to Las Vegas, Nevada; Mojave region
West Coast Terminals	38	8	9.9	Seattle, Portland, San Francisco and Los Angeles areas

(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.

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 railcars and 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, ethanol 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 throughout the U.S., primarily near large 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 and refined petroleum products between U.S. ports. The following summarizes our Terminals business segment assets, as of December 31, 2019:

	Number	Capacity (MMBbl)
Liquids terminals	50	79.5
Bulk terminals	32	—
Jones Act-qualified tankers	16	5.3

Competition

We are one of the largest independent operators of liquids terminals in North America, 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.

CO₂

Our CO₂ business segment produces, transports, and markets CO₂ for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO₂ pipelines and related assets allow us to market a complete package of CO₂ supply and transportation services to our customers. We also hold ownership interests in several oil-producing fields and own a crude oil pipeline, all located in the Permian Basin region of West Texas.

Source and Transportation Activities

CO₂ Resource Interests

Our principal market for CO₂ is for injection into mature oil fields in the Permian Basin. Our ownership of CO₂ resources as of December 31, 2019 includes:

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

(a) We do not operate this unit.

CO₂ Pipelines

The principal market for transportation on our CO₂ pipelines is to customers, including ourselves, using CO₂ for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable in the foreseeable future. The tariffs charged on (i) the Wink crude oil pipeline system are regulated by both the FERC and the Texas Railroad Commission; (ii) the Pecos Carbon Dioxide Pipeline are regulated by the Texas Railroad Commission; and (iii) the Cortez pipeline are based on a consent decree. Our other CO₂ pipelines are not regulated.

Our ownership of CO₂ and crude oil pipelines as of December 31, 2019 includes:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Transport Capacity (Bcf/d)	Supply and Market Region
CO₂ pipelines			
Cortez pipeline (53%)	569	1.5	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	337	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline (13%)(a)	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline (98%)	163	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO ₂ pipeline	113	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO ₂ pipeline	98	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline (95%)	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
(Bbls/d)			
Crude oil pipeline			
Wink pipeline	433	145,000	West Texas to Western Refining's refinery in El Paso, Texas

(a) We do not operate Bravo pipeline.

Oil and Gas Producing Activities

Oil Producing Interests

Our ownership interests in oil-producing fields located in the Permian Basin of West Texas as of December 31, 2019 include the following:

	Working Interest %	KMI Gross Developed Acres
SACROC	97	49,156
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; 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 and Gasoline Plant Interests

Owned and operated gas plants in the Permian Basin of West Texas as of December 31, 2019 include:

	Ownership Interest %	Source
Snyder gasoline plant(a)	22	The SACROC unit and neighboring CO ₂ projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51	Snyder gasoline plant
North Snyder plant	100	Snyder gasoline plant

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

Competition

Our primary competitors for the sale of CO₂ include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO₂ resources. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO₂ pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO₂ 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, 2019, 2018 and 2017, 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.

Regulation

Interstate Natural Gas Transportation and Storage Regulation

As an owner and operator of natural gas companies subject to the Natural Gas Act of 1938, we are required to provide service to shippers on our interstate natural gas pipelines and storage facilities at regulated rates that have been determined by the FERC to be just and reasonable. Recourse rates and general terms and conditions for service are set forth in posted tariffs approved by the FERC for each pipeline (including storage facilities or companies as used herein). Generally, recourse rates are based on our cost of service, including recovery of, and a return on, our investment. 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.

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates, upon mutual agreement, the pipeline is permitted to charge negotiated rates that are not bound by and are irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. 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. The actual negotiated rate agreement or a summary of such agreement must be posted as part of the pipelines' tariffs. While pipelines and their shippers may agree to a variety of negotiated rate structures depending on the shipper and circumstance, pipelines generally must use for all shippers the form of service agreement that is contained within their FERC-approved tariff. Any deviation from the *pro forma* service agreements must be filed with the FERC and only certain types of deviations in the terms and conditions of service are acceptable to the FERC.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980s, the FERC adopted a number of regulatory changes to ensure that interstate natural gas pipelines operated on a not unduly discriminatory basis and to create a more competitive and transparent environment in the natural gas marketplace. Examples include FERC regulations requiring interstate natural gas pipelines to separate their

traditional merchant sales services from their transportation and storage services and provide comparable transportation and storage services with respect to all natural gas customers. Also, natural gas pipelines must separately state the applicable rates for each unbundled service they provide (i.e., for transportation services and storage services for natural gas). To ensure a competitive transportation market, these pipelines must adhere to certain scheduling procedures, accept capacity segmentation in certain circumstances and abide by FERC-established standards of conduct when communicating with marketing affiliates.

In addition to regulatory changes initiated by the FERC, the U.S. Congress passed the Energy Policy Act of 2005. Among other things, the Energy Policy Act amended the Natural Gas Act to: (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

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 such 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 the revenues in excess of the prior tariff collected during the pendency of the investigation. 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.

The Energy Policy Act of 1992 deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our SFPP operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the SFPP pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 18 "*Litigation and Environmental*" to our consolidated financial statements.

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. A petroleum products or crude oil pipeline must, as a general rule, utilize the indexing methodology to change its rates. Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

CPUC Rate Regulation

The intrastate common carrier operations of our West Coast Refined Products operations' 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 West Coast Refined Products operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before 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.

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 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.

Safety Regulation

We are also subject to safety regulations issued by PHMSA, including those requiring us to develop and maintain pipeline integrity management programs to evaluate areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas, or HCAs, and Moderate Consequence Areas, or MCAs, where a leak or rupture could potentially do the most harm.

During September 2019, PHMSA finalized rules to be effective July 1, 2020 to expand integrity management program requirements to hazardous liquids pipelines outside of HCAs (with some exceptions) and to make certain other changes to those program requirements, including data integration and emphasis on the use of in-line inspection technology. During October 2019, PHMSA finalized rules to require operators of natural gas pipelines to (i) expand integrity management program requirements outside of HCAs (with some exceptions), and (ii) reconfirm maximum allowable operating pressure (MAOP) on certain pipelines in populated areas including HCAs. The MAOP reconfirmations must be completed by 2035. Changes in technology such as advances of in-line inspection tools, identification of additional integrity threats and changes to PHMSA regulations can have a significant impact on costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA regulations. The costs to comply with integrity management program requirements are difficult to predict. Tests performed as part of our program could result in significant capital and operating expenditures for upgrades and/or repairs deemed necessary to continue the safe and reliable operation of our pipelines. We expect to increase expenditures in the future to comply with these PHMSA regulations.

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 or "PIPES Act of 2016" requires PHMSA, among other regulators, to set minimum safety standards for underground natural gas storage facilities and allows states to set more stringent standards for intrastate pipelines. In compliance with the PIPES Act of 2016, we have implemented procedures for underground natural gas storage facilities.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which was signed into law in 2012, increased penalties for violations of safety laws and rules and may result in the imposition of more stringent regulations in the future. In 2012, PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine maximum pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the Advisory Bulletin requirements, could significantly increase our costs. Additionally, failure to locate such records to verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity management regulation, and actual expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines or facilities may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We are also subject to the requirements of the Occupational Safety and Health Administration (OSHA) and other federal and state agencies that address employee health and safety. In general, we believe current expenditures are fulfilling the OSHA requirements and protecting the health and safety of our employees. Based on new regulatory developments, we may increase expenditures in the future to comply with higher industry and regulatory safety standards. However, such increases in our expenditures, and the extent to which they might be offset, cannot be estimated at this time.

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, 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 in 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.

Canadian Regulation

The Utopia Pipeline System, owned by a joint venture that we operate and in which we own a 50% interest, originates in Ohio and terminates in Windsor, Ontario, Canada and is therefore subject to U.S. regulation as described in this section and below under the heading "*—Environmental Matters,*" as well as similar regulations promulgated by Canadian authorities with respect to natural gas liquids pipelines.

Environmental Matters

Our business operations are subject to federal, state and local laws and regulations relating to environmental protection and human health and safety. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, or at or from our 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 for 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 approvals and environmental analysis under federal and state laws, including the Clean Water Act, the National Environmental Policy Act and the Endangered Species Act. The resulting costs and liabilities could materially and negatively affect our business, financial condition, results of operations and cash flows. In addition, emission controls required under federal and state environmental laws could require significant capital expenditures at our facilities.

Environmental and human health and safety laws and regulations are subject to change. The long term trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health. There can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, 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 fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

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. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for estimable and probable environmental remediation obligations at various sites, including multi-party sites where the EPA, or similar state or Canadian agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites could increase or mitigate our actual joint and several liability exposures.

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of \$259 million as of December 31, 2019. Our aggregate reserve estimate ranges in value from approximately \$259 million to approximately \$428 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, 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 and comparable state statutes. From time to time, the EPA, as well as other U.S. federal and state regulators, consider the adoption of stricter disposal standards for non-hazardous waste. 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 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.

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, in addition to 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 clean up 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 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 new NAAQS standard. Now, certain states will have to adopt more stringent air quality regulations to meet the new NAAQS standard. These new state rules, which are expected in 2020 or 2021, will likely 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. Given the nationwide implications of the new rule, it is expected that it will have financial impacts for each of our 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 CO₂, which is naturally occurring and also a byproduct of the burning of 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 December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain GHGs, including CO₂ and methane. Our facilities are subject to these requirements. Operational and/or regulatory changes could require additional facilities to comply with GHG emissions reporting and permitting requirements.

On October 23, 2015, the EPA published as a final rule the Clean Power Plan, which sets interim and final CO₂ emission performance rates for power generating units that are fueled by coal, oil or natural gas. The final rule is the focus of legislative discussion in the U.S. Congress and litigation in federal court. On February 10, 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. In October 2017, the EPA proposed to repeal the Clean Power Plan. In August 2018, the EPA proposed to replace the Clean Power Plan and Affordable Clean Energy rule. The ultimate determination of the Clean Power Plan and Affordable Clean Energy rule remains uncertain. While we do not operate power plants that would be subject to the Clean Power Plan or the Affordable Clean Energy rule, it remains unclear what effect a final rule, if it comes into force, might have on the anticipated demand for natural gas, including natural gas that we gather, process, store and transport.

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, primarily through the planned development of emission inventories or regional GHG “cap and trade” programs. Although many of the state-level initiatives have to date been

focused on large sources of GHG emissions, such as electric power plants, it is possible that sources such as our gas-fueled compressors and processing plants could become subject to related state regulations. Various states are also proposing or have implemented stricter regulations for GHGs that go beyond the requirements of the EPA. Some of the states have implemented regulations that require additional monitoring and reporting of methane emissions. Depending on the state programs pending implementation, we could be required to conduct additional monitoring, do additional emissions reporting and/or purchase and surrender emission allowances.

Because our operations, including the compressor stations and processing plants, emit various types of GHGs, primarily methane and CO₂, such new legislation or regulation could increase the costs related to operating and maintaining the 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 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 in all cases is uncertain and may depend on events beyond their 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.

Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of hurricanes and tropical storms, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage 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. However, 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.

Because the combustion of natural gas produces less GHG emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives such as the Clean Power Plan or Affordable Clean Energy rule 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 CO₂ 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.

Other

Employees

We employed 11,086 full-time personnel at December 31, 2019, including approximately 954 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2020 and 2023. We consider relations with our employees to be good.

Most of our employees are employed by us and a limited number of our subsidiaries and provide services to one or more of our business units. The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated to our subsidiaries. Our human resources department provides the administrative support necessary to implement these payroll and benefits services, and the related administrative costs are allocated to our subsidiaries pursuant to

our board-approved expense allocation policy. The effect of these arrangements is that each business unit bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs.

Properties

We believe that 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 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 that 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, oil and other products in the geographic areas that they serve. Our business also depends in part on the levels of demand for natural gas, oil, NGL, refined petroleum products, CO₂, 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. For example, without additions to oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may reduce or shut down production during times of lower product prices or higher production costs to the extent they become uneconomic. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our pipelines and related facilities may not be able to maintain existing volumes of throughput. 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.

Changes in the business environment, 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. In addition, changes in the overall demand for hydrocarbons, 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 oil and gas industry participants. In addition, public sentiment surrounding the potential risks posed by climate change and emerging technologies have resulted in an increased demand for energy efficiency and a transition to energy provided from renewable energy sources, rather than fossil fuels, and fuel-efficient alternatives such as hybrid and electric vehicles. These factors could result in not only increased costs for producers of hydrocarbons but also an overall decrease in the demand for hydrocarbons. 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. 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. In addition, irrespective of supply of or demand for products we handle, implementation of new regulations or changes to existing regulations affecting the energy industry could have a material adverse effect on us. See *“—The FERC or the CPUC may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, 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.”*

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

We regularly undertake major 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. 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. A variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way 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 consideration of changes to its Certificate Policy Statement. Such factors can be exacerbated by public opposition to our projects. See *“—We are subject to reputational risks and risks relating to public opinion.”* For example, changing public attitudes toward pipelines bearing fossil fuels may impede our ability to secure rights-of-way or governmental reviews and authorizations on a timely basis or at all. 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. 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.

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.

The volatility of oil, NGL and natural gas prices could adversely affect our CO₂ business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.

The revenues, cash flows, profitability and future growth of some of our businesses depend to a large degree on prevailing oil, NGL and natural gas prices. Our CO₂ business segment (and the carrying value of its oil, NGL and natural gas producing properties) and certain midstream businesses within our Natural Gas Pipelines business segment depend to a large degree, and certain businesses within our Product Pipelines business segment depend to a lesser degree, on prevailing oil, NGL and natural gas prices. For 2020, we estimate that every \$1 change in the average WTI crude oil price per barrel would impact our DCF by approximately \$5 million, each \$0.10 per MMBtu change in the average price of natural gas would impact DCF by approximately \$1 million, and each 1% change in the ratio of the weighted average NGL price per barrel to the average WTI crude oil price per barrel would impact DCF by approximately \$2 million.

Prices for oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for 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 Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political instability in oil producing countries; (vi) the foreign supply of and demand for 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.”*

A sharp decline in the prices of oil, NGL or natural gas, or a prolonged unfavorable price environment, would result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell oil, NGL, or natural gas, and could have a material adverse effect on the carrying value of our CO₂ business segment's proved reserves. If 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.

In recent decades, there have been periods worldwide of both overproduction and underproduction of hydrocarbons, and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The cycles of excess or short supply of crude oil or natural gas have placed pressures on prices and resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A *“Quantitative and Qualitative Disclosures About Market Risk-Energy Commodity 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 the loading and unloading of 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 such as natural disasters, 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, 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 economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. 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 will have a negative impact on our operating results and cash flow. See “—The volatility of oil, NGL and natural gas prices could adversely affect our CO₂ business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.”

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. Our counterparties are subject to their own operating, market, financial and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. Oil, NGL and natural gas prices were all lower on average in 2019 compared to 2018, and natural gas prices have continued to decline so far in 2020. Further deterioration in oil prices, or a continuation of the existing low natural gas or NGL price environment, would likely cause severe financial distress to some of our customers with direct commodity price exposure and may result in additional customer bankruptcies. Further, the security that is permitted to be obtained from such customers may be limited 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. 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 of such customers or counterparties files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion, of amounts owed 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.

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 evaluate and pursue assets and businesses that we believe will complement or expand our operations in accordance with our growth strategy. We cannot provide any assurance that we will be able to complete acquisitions in the future or achieve the desired results from any acquisitions we do complete. Any acquired business 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.

If we do not successfully integrate acquisitions, we may not realize anticipated operating advantages and cost savings. Integration of acquired companies 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.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition will depend upon our ability to manage those operations and to eliminate redundant and excess costs. 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.

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. 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. Potential impacts of negative public opinion or reputational issues may include delays or stoppages in expansion projects, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support from regulatory authorities, challenges to regulatory approvals, difficulty securing financing for and cost overruns affecting expansion projects and the degradation of our business generally.

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 revenue loss, reduction in customer base, delays in obtaining, or challenges to, regulatory approvals with respect to growth projects and decreased value of our securities and our business.

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.

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 CO₂ 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.

The development of crude oil and gas properties involves risks that may result in a total loss of investment.

The business of 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, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions, may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

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 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.

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 with new hedging arrangements. To the extent then-existing underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions.

The accounting standards regarding hedge accounting are very complex, and even 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 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 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Hedging Activities" and Note 14 "Risk Management" to our consolidated financial statements.

A breach of information security or failure of one or more key information technology or operational (IT) 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 IT 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 processing necessary to manage our business.

While we have implemented and maintain a cybersecurity program designed to protect our IT and data systems from such attacks, we can provide no assurance that our cybersecurity program will be effective. The risk of a disruption or breach of our operational systems, or the compromise of the data processed in connection with our operations, through an act of terrorism or cyber sabotage event has increased as attempted attacks 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 and may 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 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 from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. In the future, we may be required to expend additional resources to continue to enhance our information security measures 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 that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or "cyber sabotage" events. For example, in 2018, a cyberattack on a shared data network forced four U.S. natural gas pipeline operators to temporarily shut down computer communications with their customers. Potential targets include our pipeline systems, terminals, processing plants 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,

damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition or could harm our 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 and phenomena could potentially damage or destroy our assets and disrupt the supply of the products we transport. In the third quarter of 2017, Hurricane Harvey caused disruptions in our operations and damage to our assets near the Texas Gulf Coast requiring approximately \$45 million in repair costs, approximately \$10 million of which was not recoverable through insurance. For more information regarding the impact of Hurricane Harvey on our assets and operating results, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations." Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of weather, and increased frequency of extreme precipitation and flooding. These climate-related changes could damage physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. 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. Natural disasters and phenomena can similarly affect the facilities of our customers. 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 Items 1 and 2 "Business and Properties—Narrative Description of Business—Environmental Matters."

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, CO₂, 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 right-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.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require 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.

If we are unable to retain our executive officers, our ability to execute our business strategy, including our growth strategy, may be hindered.

Our success depends in part on the performance of and our ability to retain our executive officers, particularly Richard D. Kinder, our Executive Chairman and one of our founders, Steve Kean, our Chief Executive Officer, and Kim Dang, our President. Along with the other members of our senior management, Mssrs. Kinder and Kean and Ms. Dang have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean, Ms.

Dang or our other executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

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 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.

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, 2019, we had approximately \$33.4 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 increased costs of capital or a reduction in the availability of credit.

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 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 on favorable terms. Further, to the extent that financial markets characterize investments that might be impacted by public perception of, or federal or state regulation related to, climate change and GHG emissions as a financial risk, our cost of and ability to access capital may be adversely affected. 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. Public opinion toward industries linked to fossil fuels continues to evolve. 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, 2019, approximately \$8.9 billion of our approximately \$33.4 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. Should interest rates increase, the amount of cash required to service variable-rate debt would increase, as would our costs to refinance maturities of existing indebtedness, and our earnings and cash flows could be adversely affected.

Amounts drawn under our revolving credit facility may bear interest rates in relation to LIBOR, depending on our selection of repayment options, and certain of our outstanding interest rate swap agreements have a floating interest rate in relation to one-month LIBOR or three-month LIBOR. In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of 2021. Financial industry working groups are developing replacement rates and methodologies to transition existing agreements that depend on LIBOR as a reference rate; however, we can provide no assurance that market-accepted rates and transition methodologies will be available and finalized at the time of LIBOR cessation. If clear market standards and transition methodologies have not developed by the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our revolving credit facility and our interest rate swap agreements. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our earnings and cash flows.

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

Acquisitions and growth capital expenditures may require access to external capital. Limitations on our access to external financing sources could impair our ability to grow.

We have limited amounts of internally generated cash flows to fund acquisitions and growth capital expenditures. If our internally generated cash flows are not sufficient to fund one or more capital projects or acquisitions, we may have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisitions and growth capital expenditures. Limitations on our access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, could impair our ability to execute our growth strategy.

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 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 address properly 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.

Risks Related to Regulation

The FERC or the CPUC may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC 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 the CPUC 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. 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 that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 18 “*Litigation and Environmental*” to our consolidated financial statements, to the rates we charge on our pipelines. 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 regulation and oversight by federal, state and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these agencies, have the potential to adversely affect our profitability. In addition, a certain degree of regulatory uncertainty is created by the current U.S. presidential administration because it remains unclear specifically what the current administration may do with respect to future policies and regulations that may affect us. Regulation affects almost every part of our business and extends to such matters as (i) federal, state and local taxation; (ii) rates (which include tax, 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 costs of raw materials, such as steel, which may be affected by tariffs or otherwise; (vii) the integrity, safety and security of facilities and operations; (viii) acquisitions or dispositions of assets or businesses; (ix) the acquisition, extension, disposition or abandonment of services or facilities; (x) reporting and information posting requirements; (xi) the maintenance of accounts and records; and (xii) relationships with affiliated companies involved in various aspects of the energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws, regulations or policy changes sometimes arise from unexpected sources. New laws or regulations, unexpected policy changes or interpretations of existing laws or regulations, 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—Regulation.*"

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

Our operations are subject to 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 present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. 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 an accidental 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. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. 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 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 the hazardous substances released and wastes disposed on them may be subject to laws in the U.S. such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. 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. 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. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, 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 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 integrity at the federal and state level. There are, for example, federal guidelines issued by the U.S. Department of Transportation (DOT) for pipeline companies in the areas of testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs relate to pipeline integrity testing and repairs. 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 “High Consequence Areas” 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 the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

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. There can be no assurance as to the amount or timing of future expenditures for pipeline 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 risk 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 CO₂, including the EPA programs to control GHG emissions 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 CO₂ (for example, from our McElmo Dome CO₂ field), even when such production is not emitted to the atmosphere. Proposed approaches to further regulate GHG emissions include establishing GHG “cap and trade” programs, increased efficiency standards, 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 and could require us 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.

Finally, many climate models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage 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.

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 hydraulic fracturing, 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 in which the use of hydraulic fracturing is prevalent. Oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. The oil and gas industry is increasingly relying on supplies of hydrocarbons from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of hydrocarbons from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by oil and gas exploration and production operators in the completion of certain oil and gas wells. There have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities 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.

In addition, many states are promulgating stricter requirements not only for wells but also compressor stations and other facilities in the oil and gas industry sector. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, 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. These laws and regulations may adversely affect our oil and gas development and production activities.

Derivatives regulation could have an adverse effect on our ability to hedge risks associated with our business.

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. Those rules and regulations are largely complete; although in December 2016, the CFTC re-proposed new rules pursuant to the Dodd-Frank Act that would institute broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. Thus, we cannot predict how further rules and regulations will affect us.

If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

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.

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.*

We no longer 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), except for one terminal that is in temporary idle status with the Mine Safety and Health Administration. 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, 2019.

PART II

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

Our Class P common stock is listed for trading on the NYSE under the symbol "KMI."

As of February 7, 2020, we had 10,886 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.

Item 6. Selected Financial Data.

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report for more information.

Five-Year Review
Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2019	2018	2017	2016	2015
(In millions, except per share amounts)					
Income and Cash Flow Data:					
Revenues	\$ 13,209	\$ 14,144	\$ 13,705	\$ 13,058	\$ 14,403
Operating income	4,873	3,794	3,529	3,538	2,378
Earnings (losses) from equity investments	101	617	428	(113)	384
Net income	2,239	1,919	223	721	208
Net income attributable to Kinder Morgan, Inc.	2,190	1,609	183	708	253
Net income available to common stockholders	2,190	1,481	27	552	227
Class P Shares					
Basic Earnings Per Common Share From Continuing Operations	\$ 0.96	\$ 0.66	\$ 0.01	\$ 0.25	\$ 0.10
Basic Weighted Average Common Shares Outstanding	2,264	2,216	2,230	2,230	2,187
Dividends per common share declared for the period(a)	\$ 1.00	\$ 0.80	\$ 0.50	\$ 0.50	\$ 1.61
Dividends per common share paid in the period(a)	0.95	0.725	0.50	0.50	1.93
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	\$ 36,419	\$ 37,897	\$ 40,155	\$ 38,705	\$ 40,547
Total assets	74,157	78,866	79,055	80,305	84,104
Current portion of debt	2,477	3,388	2,828	2,696	821
Long-term debt(b)	30,883	33,205	34,088	36,205	40,732

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.

(b) Excludes debt fair value adjustments.

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 2019, found in Items 1 and 2 "Business and Properties—General Development of Business—Recent Developments;" (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors;" and (iv) a discussion of forward-looking statements, found in "Information Regarding Forward-Looking Statements" at the beginning of this report.

A comparative discussion of our 2018 to 2017 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, 2018 filed with the SEC on February 8, 2019.

General

As an energy infrastructure owner and operator in multiple facets of the various U.S. energy industries and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future. We have four business segments as further described below.

Natural Gas Pipelines

This segment owns and operates (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas gathering systems and processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG regasification, liquefaction and storage facilities.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets 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 the capacity. Similarly, the Texas Intrastate Natural Gas Pipeline operations, currently derives approximately 76% 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, 2019, the remaining weighted average contract life of our natural gas transportation contracts (including intrastate pipelines' sales portfolio) was approximately seven years. Our LNG regasification and liquefaction and associated storage contracts are subscribed under long-term agreements.

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 their 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.

Products Pipelines

This segment owns and operates refined petroleum products, crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, propane, ethane, crude oil and condensate to various markets. This segment also owns and/or operates associated product terminals and petroleum pipeline transmix facilities.

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 biofuels. 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 either pursuant to (i) FERC and state tariffs and (ii) long-term contracts that normally contain minimum volume commitments and terminalling. As a result of these contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term; however, in the longer term 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 level of oil and gas drilling activity in the respective producing 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.

Terminals

This segment owns and operates (i) liquids and bulk terminal facilities located throughout the U.S. that store and handle various commodities including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke; and (ii) Jones Act-qualified tankers.

The factors impacting our Terminals business segment generally differ between liquid and bulk terminals, and in the case of a bulk terminal, the type of product being handled or stored. 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 length of the underlying service contracts (which on average 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.

In addition to liquid and bulk terminals, we also own Jones Act-qualified tankers in our Terminals business segment. As of December 31, 2019, we have sixteen Jones Act-qualified tankers that operate in the marine transportation of crude oil, condensate and refined products in the U.S. and are primarily operating pursuant to multi-year fixed price charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

CO₂

The CO₂ segment (i) manages the production, transportation and marketing of CO₂ to oil fields that use CO₂ as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) owns interests in and operates oil fields and gasoline processing plants in West Texas; and (iii) owns and operates a crude oil pipeline system in West Texas.

The CO₂ source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2019, had a remaining average contract life of approximately nine years. CO₂ sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2019, and utilizing the average oil price per barrel contained in our 2020 budget, approximately 97% of our revenue is based on a fixed fee or floor price, and 3% fluctuates with the price of oil. In the long-term, our success in this portion of the CO₂ business segment is driven by the demand for CO₂. However, short-term changes in the demand for CO₂ typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO₂ 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 will 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, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with the hedges allocated to oil, was \$49.49 per barrel in 2019 and \$57.83 per barrel in 2018. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged \$55.12 per barrel in 2019 and \$58.63 per barrel in 2018.

Also, see Note 15 “Revenue Recognition” to our consolidated financial statements for more information about the types of contracts and revenues recognized for each of our segments.

KML

Sale of U.S. Portion of Cochin Pipeline and KML

On December 16, 2019, we closed on two cross-conditional transactions resulting in the sale of the U.S. portion of the Cochin Pipeline and all the outstanding equity of KML, including our 70% interest, to Pembina Pipeline Corporation (Pembina) (together, the “KML and U.S. Cochin Sale”). We recognized a pre-tax net gain of \$1,296 million from these transactions included within “(Gain) loss on divestitures and impairments, net” on our accompanying consolidated statement of income during the year ended December 31, 2019. We received cash proceeds of \$1,553 million, net of a working capital adjustment, for the U.S. portion of the Cochin Pipeline, which was used to pay down debt. KML common shareholders received 0.3068 shares of Pembina common equity for each share of KML common equity. For our 70% interest in KML, we received approximately 25 million shares of Pembina common equity, with a pre-tax fair value on the transaction date of approximately \$892 million. The fair market value as of December 31, 2019 of the Pembina common shares was \$925 million and is reported as “Marketable securities at fair value” within our accompanying consolidated balance sheet. Level 1 inputs were utilized to measure the fair value of the Pembina common stock. The Pembina common shares were subsequently sold on January 9, 2020, and we received proceeds of approximately \$907 million (\$764 million after tax) which will be used to pay down debt. The assets sold were part of our Natural Gas Pipelines and Terminals business segments.

Sale of Trans Mountain Pipeline System and Its Expansion Project

On August 31, 2018, KML completed the sale of the TMPL, the TMEP and the Puget Sound pipeline system for net cash consideration of C\$4.43 billion (U.S.\$3.4 billion), which is the contractual purchase price of C \$4.5 billion net of a preliminary working capital adjustment (the “TMPL Sale”). These assets comprised our Kinder Morgan Canada business segment. We recognized a pre-tax gain from the TMPL Sale of \$595 million within “(Gain) loss on divestitures and impairments, net” in our accompanying consolidated statement of income during the year ended December 31, 2018. During the first quarter of 2019, KML settled the remaining \$28 million of working capital adjustments, which amount was substantially accrued for as of December 31, 2018.

On January 3, 2019, KML distributed the net proceeds from the TMPL Sale to its shareholders as a return of capital. Public owners of KML’s restricted voting shares, reflected as noncontrolling interests by us, received approximately \$0.9 billion (C\$1.2 billion), and most of our approximate 70% portion of the net proceeds of \$1.9 billion (C\$2.5 billion) (after Canadian tax) were used to repay our outstanding commercial paper borrowings of \$0.4 billion, and in February 2019, to pay down approximately \$1.3 billion of maturing long-term debt.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. 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.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others 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) calculations of possible asset and equity investment impairment charges, and (b) calculation for the annual goodwill impairment test; (v) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (vi) provisions for uncollectible accounts receivables; (vii) computation of the gain or loss, if any, on assets sold in whole or in part; and (viii) exposures under contractual indemnifications.

For a summary of our significant accounting policies, see Note 2 “*Summary of Significant Accounting Policies*” to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

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. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, 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. and Canadian 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. In general, we expense legal costs as incurred. When we identify contingent liabilities that are probable, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. 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 legal proceedings, see Note 18 “*Litigation and Environmental*” to our consolidated financial statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate goodwill for impairment on May 31 of each year. At year end and during other interim periods we evaluate our reporting units for events and changes that could indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, and technology-based assets. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as “Other intangibles, net” in our accompanying consolidated balance sheets.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices, foreign currency exposure on Euro-denominated debt, and until our recent divestitures of our Canadian assets, net investments in foreign operations, and to balance our exposure to fixed and variable interest rates, and we believe that these derivative contracts are, or were in respect to our Canadian operations, generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the hedged risk, and any component

excluded from the computation of the effectiveness of the derivative contract must be recognized in earnings over the life of the hedging instrument by using a systematic and rational method.

All of our derivative contracts are recorded at estimated fair value. We utilize published prices, broker quotes, and estimates of market prices to estimate the fair value of these contracts; however, actual amounts could vary materially from estimated fair values as a result of changes in market prices. In addition, changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. For more information on our hedging activities, see Note 14 "Risk Management" to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit (OPEB) plans based on their overfunded or underfunded status. As of December 31, 2019, our pension plans were underfunded by \$620 million, and our OPEB plans were fully funded. Our pension and OPEB obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our pension and OPEB plans which applies the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The selection of these assumptions 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. As of December 31, 2019, we had deferred net losses of approximately \$434 million in pre-tax accumulated other comprehensive loss related to our pension and OPEB plans.

The following table shows the 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, 2019:

	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	\$ (11)	\$ 196	\$ —	\$ 23
Expected return on plan assets	(18)	—	(3)	—
Rate of compensation increase	2	(10)	—	—
Health care cost trends	—	—	2	(14)
One percent decrease in:				
Discount rates	13	(230)	—	(27)
Expected return on plan assets	18	—	3	—
Rate of compensation increase	(2)	10	—	—
Health care cost trends	—	—	(2)	12

(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

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 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 for the amount that is more likely than not to 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.

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*"), net income and net income available to common stockholders, 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, Net Debt and Net Debt to Adjusted EBITDA.

For segment reporting purposes, effective January 1, 2019, certain assets were transferred among our business segments. As a result, individual segment results for the year ended December 31, 2018 have been reclassified to conform to the current presentation in the following MD&A tables. The reclassified amounts were not material.

GAAP Financial Measures

The Consolidated Earnings Results for the years ended December 31, 2019 and 2018 present Segment EBDA, net income and net income available to common stockholders 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 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, but typically either (i) do not have a cash impact (for example, 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). See tables included in “—Consolidated Earnings Results (GAAP)—Certain Items Affecting Consolidated Earnings Results,” “—Non-GAAP Financial Measures—Reconciliation of Net Income (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 “—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests” below.

Adjusted Earnings

Adjusted Earnings is calculated by adjusting net income available to common stockholders 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 the Company’s ability to generate earnings. We believe the GAAP measure most directly comparable to Adjusted Earnings is net income available to common stockholders. Adjusted Earnings per share uses Adjusted Earnings and applies the same two-class method used in arriving at basic earnings per common share. See “—Non-GAAP Financial Measures—Reconciliation of Net Income Available to Common Stockholders (GAAP) to Adjusted Earnings to DCF” below.

DCF

DCF is calculated by adjusting net income available to common stockholders 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. 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 common stock 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 available to common stockholders. DCF per common share is DCF divided by average outstanding common shares, including restricted stock awards that participate in common share dividends. See “—Non-GAAP Financial Measures—Reconciliation of Net Income Available to Common Stockholders (GAAP) to Adjusted Earnings to DCF” and “—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 segment 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, our share of unconsolidated joint venture DD&A and income tax expense (net of our partners’ share of consolidating joint venture DD&A and income tax expense), and net income attributable to noncontrolling interests that is further adjusted for KML noncontrolling interests (net of its applicable Certain Items). Adjusted EBITDA is used by management and external users, in conjunction with our Net Debt (as described further below), to evaluate certain leverage metrics. Therefore, we believe Adjusted EBITDA is useful to investors. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income. (See “—Adjusted Segment EBDA to Adjusted EBITDA to DCF” and “—Non-GAAP Financial Measures—Reconciliation of Net Income (GAAP) to Adjusted EBITDA” below).

Net Debt

Net Debt is a non-GAAP financial measure that is useful to investors and other users of our financial information in evaluating our leverage. Net Debt is calculated by subtracting from debt (i) cash and cash equivalents; (ii) the preferred interest in the general partner of KMP (which was redeemed in January 2020); (iii) debt fair value adjustments; and (iv) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. We believe the most comparable

measure to Net Debt is debt net of cash and cash equivalents. Our Net Debt-to-Adjusted EBITDA ratio was 4.3 as of December 31, 2019.

Consolidated Earnings Results (GAAP)

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

	Year Ended December 31,	
	2019	2018
	(In millions)	
Segment EBDA(a)		
Natural Gas Pipelines	\$ 4,661	\$ 3,540
Products Pipelines	1,225	1,209
Terminals	1,506	1,175
CO ₂	681	759
Kinder Morgan Canada(b)	(2)	720
Total segment EBDA	8,071	7,403
DD&A	(2,411)	(2,297)
Amortization of excess cost of equity investments	(83)	(95)
General and administrative and corporate charges	(611)	(588)
Interest, net	(1,801)	(1,917)
Income before income taxes	3,165	2,506
Income tax expense	(926)	(587)
Net income	2,239	1,919
Net income attributable to noncontrolling interests	(49)	(310)
Net income attributable to Kinder Morgan, Inc.	2,190	1,609
Preferred stock dividends	—	(128)
Net income available to common stockholders	\$ 2,190	\$ 1,481

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

(b) 2019 amount represents a final working capital adjustment; otherwise, as a result of the TMPL Sale on August 31, 2018, this segment does not have results of operations on a prospective basis.

Certain Items Affecting Consolidated Earnings Results

	Year Ended December 31,						Adjusted amounts increase/(decrease) to earnings
	2019			2018			
	GAAP	Certain Items	Adjusted	GAAP	Certain Items	Adjusted	
	(In millions)						
Segment EBDA							
Natural Gas Pipelines	\$ 4,661	\$ (51)	\$ 4,610	\$ 3,540	\$ 665	\$ 4,205	\$ 405
Products Pipelines	1,225	33	1,258	1,209	18	1,227	31
Terminals	1,506	(332)	1,174	1,175	34	1,209	(35)
CO ₂	681	26	707	759	148	907	(200)
Kinder Morgan Canada	(2)	2	—	720	(596)	124	(124)
Total Segment EBDA(a)	8,071	(322)	7,749	7,403	269	7,672	77
DD&A and amortization of excess cost of equity investments	(2,494)	—	(2,494)	(2,392)	—	(2,392)	(102)
General and administrative and corporate charges(a)	(611)	13	(598)	(588)	24	(564)	(34)
Interest, net(a)	(1,801)	(15)	(1,816)	(1,917)	26	(1,891)	75
Income before income taxes	3,165	(324)	2,841	2,506	319	2,825	16
Income tax expense(b)	(926)	299	(627)	(587)	(58)	(645)	18
Net income	2,239	(25)	2,214	1,919	261	2,180	34
Net income attributable to noncontrolling interests(a)	(49)	(4)	(53)	(310)	240	(70)	17
Preferred stock dividends	—	—	—	(128)	—	(128)	128
Net income available to common stockholders	\$ 2,190	\$ (29)	\$ 2,161	\$ 1,481	\$ 501	\$ 1,982	\$ 179

(a) For a more detailed discussion of these Certain Items, see the footnotes to the tables within “—Segment Earnings Results” and “—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests” below.

(b) The combined net effect of the Certain Items represents the income tax provision on Certain Items plus discrete income tax items.

Year Ended December 31, 2019 vs. 2018

Income before income taxes increased \$659 million in 2019 compared to 2018. The increase was due primarily to greater contributions from the Natural Gas Pipelines segment, and lower interest expense, partially offset by reduced contributions from the CO₂ segment and the Trans Mountain Sale in 2018. Net income before income taxes for 2019 was further affected by a gain associated with the KML and U.S. Cochin Sale, which was partly offset by non-cash impairments of our investment in Ruby Pipeline (driven by upcoming contract expirations and competing natural gas supplies) and certain gathering and processing assets in Oklahoma and North Texas (driven by reduced drilling activity). Net income was further impacted by non-cash impairments taken during 2018.

After giving effect to Certain Items, which are discussed in more detail in the discussions that follow, the remaining increase of \$16 million from the prior year in income before income taxes is primarily attributable to increased performance from our Natural Gas Pipelines business segment and decreased interest expense, net, partially offset by lower earnings from our CO₂ business segment, lower earnings from our Kinder Morgan Canada business segment as a result of the TMPL Sale and increased DD&A expense and general and administrative and corporate charges.

Non-GAAP Financial Measures

Reconciliation of Net Income Available to Common Stockholders (GAAP) to Adjusted Earnings to DCF

	Year Ended December 31,	
	2019	2018
	(In millions)	
Net income available to common stockholders (GAAP)	\$ 2,190	\$ 1,481
Total Certain Items	(29)	501
Adjusted Earnings(a)	2,161	1,982
DD&A and amortization of excess cost of equity investments for DCF(b)	2,867	2,752
Income tax expense for DCF(a)(b)	714	710
Cash taxes(c)	(90)	(77)
Sustaining capital expenditures(c)	(688)	(652)
Other items(d)	29	15
DCF	\$ 4,993	\$ 4,730

Adjusted Segment EBDA to Adjusted EBITDA to DCF

	Year Ended December 31,	
	2019	2018
	(In millions, except per share amounts)	
Natural Gas Pipelines	\$ 4,610	\$ 4,205
Products Pipelines	1,258	1,227
Terminals	1,174	1,209
CO ₂	707	907
Kinder Morgan Canada	—	124
Adjusted Segment EBDA(a)	7,749	7,672
General and administrative and corporate charges(a)	(598)	(564)
KMI's share of joint venture DD&A and income tax expense(a)(e)	487	472
Net income attributable to noncontrolling interests (net of KML noncontrolling interests and Certain Items) (a)	(20)	(12)
Adjusted EBITDA	7,618	7,568
Interest, net(a)	(1,816)	(1,891)
Cash taxes(c)	(90)	(77)
Sustaining capital expenditures(c)	(688)	(652)
KML noncontrolling interests DCF adjustments(f)	(60)	(105)
Preferred stock dividends	—	(128)
Other items(d)	29	15
DCF	\$ 4,993	\$ 4,730
Adjusted Earnings per common share	\$ 0.95	\$ 0.89
Weighted average common shares outstanding for dividends(g)	2,276	2,228
DCF per common share	\$ 2.19	\$ 2.12
Declared dividends per common share	\$ 1.00	\$ 0.80

(a) Amounts are adjusted for Certain Items.

(b) Includes KMI's share of DD&A or income tax expense from joint ventures, net of DD&A or income tax expense attributable to KML noncontrolling interests, as applicable. See tables included in "—Supplemental Information" below.

(c) Includes KMI's share of cash taxes or sustaining capital expenditures from joint ventures, as applicable. See tables included in "—Supplemental Information" below.

(d) Includes non-cash pension expense and non-cash compensation associated with our restricted stock program.

(e) KMI's share of unconsolidated joint venture DD&A and income tax expense, net of consolidating joint venture partners' share of DD&A.

(f) The combined net income, DD&A and income tax expense adjusted for Certain Items, as applicable, attributable to KML noncontrolling interests. See table included in "—Supplemental Information" below.

- (g) Includes restricted stock awards that participate in common share dividends.

Reconciliation of Net Income (GAAP) to Adjusted EBITDA

	Year Ended December 31,	
	2019	2018
	(In millions)	
Net income (GAAP)	\$ 2,239	\$ 1,919
Certain Items:		
Fair value amortization	(29)	(34)
Legal, environmental and taxes other than income tax reserves	46	12
Change in fair market value of derivative contracts(a)	(24)	80
(Gain) loss on divestitures and impairments, net(b)	(280)	317
Hurricane damage (recoveries), net	—	(24)
Income tax Certain Items	299	(58)
Noncontrolling interests associated with Certain Items	(4)	240
Other	(37)	(32)
Total Certain Items	(29)	501
DD&A and amortization of excess cost of equity investments	2,494	2,392
Income tax expense(c)	627	645
KMI's share of joint venture DD&A and income tax expense(c)(d)	487	472
Interest, net(c)	1,816	1,891
Net income attributable to noncontrolling interests (net of KML noncontrolling interests(c))	(16)	(252)
Adjusted EBITDA	\$ 7,618	\$ 7,568

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

(b) 2019 amount primarily includes: (i) a \$1,296 million pre-tax gain on the KML and U.S. Cochin Sale and a pre-tax loss of \$364 million for asset impairments, related to gathering and processing assets in Oklahoma and northern Texas in our Natural Gas Pipelines business segment and oil and gas producing assets in our CO₂ business segment, which are reported within "(Gain) loss on divestitures and impairments, net" on the accompanying consolidated statement of income and (ii) a pre-tax \$650 million loss for an impairment of our investment in Ruby Pipeline which is reported within "Earnings from equity investments" on the accompanying consolidated statement of income. 2018 amount primarily includes (i) pre-tax losses totaling \$774 million for asset impairments associated with certain gathering and processing assets in Oklahoma, certain oil and gas properties, certain northeast terminal assets, and a project write-off associated with the Utica Marcellus Texas pipeline, partially offset by a \$595 million pre-tax gain on the TMPL Sale, both reported within "(Gain) loss on divestitures and impairments, net" on the accompanying consolidated statement of income and (ii) a \$90 million pre-tax loss for an impairment of our investment in Gulf LNG Holdings Group, LLC (Gulf LNG) which was driven by a ruling by an arbitration panel affecting a customer contract, net of our share of earnings recognized by Gulf LNG on the respective customer contract, both of which are included in "Earnings from equity investments" on the accompanying consolidated statement of income.

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

(d) KMI's share of unconsolidated joint venture DD&A and income tax expense, net of consolidating joint venture partners' share of DD&A.

Supplemental Information

	Year Ended December 31,	
	2019	2018
	(In millions)	
DD&A (GAAP)	\$ 2,411	\$ 2,297
Amortization of excess cost of equity investments (GAAP)	83	95
DD&A and amortization of excess cost of equity investments	2,494	2,392
Our share of joint venture DD&A	392	390
DD&A attributable to KML noncontrolling interests	(19)	(30)
DD&A and amortization of excess cost of equity investments for DCF	\$ 2,867	\$ 2,752
Income tax expense (GAAP)	\$ 926	\$ 587
Certain Items	(299)	58
Income tax expense(a)	627	645
Our share of taxable joint venture income tax expense(a)	95	82
Income tax expense attributable to KML noncontrolling interests(a)	(8)	(17)
Income tax expense for DCF(a)	\$ 714	\$ 710
Net income attributable to KML noncontrolling interests	\$ 29	\$ 297
KML noncontrolling interests associated with Certain Items	4	(239)
KML noncontrolling interests(a)	33	58
DD&A attributable to KML noncontrolling interests	19	30
Income tax expense attributable to KML noncontrolling interests(a)	8	17
KML noncontrolling interests DCF adjustments(a)	\$ 60	\$ 105
Net income attributable to noncontrolling interests (GAAP)	\$ 49	\$ 310
Less: KML noncontrolling interests(a)	33	58
Net income attributable to noncontrolling interests (net of KML noncontrolling interests(a))	16	252
Noncontrolling interests associated with Certain Items	4	(240)
Net income attributable to noncontrolling interests (net of KML noncontrolling interests and Certain Items)	\$ 20	\$ 12
<i>Additional joint venture information:</i>		
Our share of joint venture DD&A	\$ 392	\$ 390
Our share of joint venture income tax expense(a)	95	82
Our share of joint venture DD&A and income tax expense(a)	\$ 487	\$ 472
Our share of taxable joint venture cash taxes	\$ (61)	\$ (68)
Our share of joint venture sustaining capital expenditures	\$ (114)	\$ (105)

(a) Amounts are adjusted for Certain Items.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,	
	2019	2018
	(In millions, except operating statistics)	
Revenues	\$ 8,170	\$ 8,855
Operating expenses	(4,213)	(5,218)
Gain (loss) on divestitures and impairments, net	677	(630)
Other income	3	1
(Losses) earnings from equity investments	(29)	493
Other, net	53	39
Segment EBDA	4,661	3,540
Certain Items(a)(b)	(51)	665
Adjusted Segment EBDA	\$ 4,610	\$ 4,205
Change from prior period		
	Increase/(Decrease)	
Adjusted revenues	\$ (631)	
Adjusted Segment EBDA	405	
Volumetric data(c)		
Transport volumes (BBtu/d)	36,793	32,821
Sales volumes (BBtu/d)	2,420	2,472
Gathering volumes (BBtu/d)	3,382	2,972
NGLs (MBbl/d)	125	114

Certain Items affecting Segment EBDA

- (a) Includes revenue Certain Item amounts of \$12 million and \$(42) million for 2019 and 2018, respectively. These Certain Item amounts are primarily related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas and NGL sales in the 2019 and 2018 periods, and additionally in the 2018 period, to a transportation contract refund and the early termination of a long-term natural gas transportation contract.
- (b) Includes non-revenue Certain Item amounts of \$(63) million and \$707 million for 2019 and 2018, respectively. 2019 amount includes (i) a \$957 million gain on the sale of Cochin pipeline; (ii) a \$650 million non-cash impairment loss related to our investment in Ruby; (iii) \$157 million and \$133 million non-cash losses on impairments of certain gathering and processing assets in North Texas and Oklahoma, respectively; (iv) an increase in earnings of \$23 million for a gain on an ownership rights contract with a joint venture partner; and (v) a \$16 million increase in earnings related to our share of certain equity investees' amortization of regulatory liabilities. 2018 amount includes (i) a \$600 million non-cash impairment loss of certain gathering and processing assets in Oklahoma; (ii) a net loss of \$89 million in our equity investment in Gulf LNG Holdings Group, LLC (Gulf LNG), due to a ruling by an arbitration panel affecting a customer contract, which resulted in a non-cash impairment of our investment partially offset by our share of earnings recognized by Gulf LNG on the respective customer contract; (iii) an increase in earnings of \$41 million for our share of certain equity investees' 2017 Tax Reform provisional adjustments; (iv) a decrease in earnings of \$36 million associated with a project write-off on the Utica Marcellus Texas pipeline; and (v) a decrease in earnings of \$24 million related to certain litigation matters.

Other

- (c) Joint venture throughput is reported at our ownership share.

Below are the changes in both Adjusted Segment EBDA and adjusted revenues between 2019 and 2018:

Year Ended December 31, 2019 versus Year Ended December 31, 2018

	Adjusted Segment EBDA increase/(decrease)		Adjusted revenues increase/(decrease)	
	(In millions, except percentages)			
North Region	\$ 130	10%	\$ 125	8%
Midstream	123	10%	(934)	(17)%
West Region	106	11%	101	8%
South Region	38	5%	70	21%
Other	8	133%	9	150%
Intrasegment eliminations	—	—%	(2)	(8)%
Total Natural Gas Pipelines	\$ 405	10%	\$ (631)	(7)%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2019 and 2018:

- North Region's increase of \$130 million (10%) was the result of an increase in earnings on TGP driven by expansion projects placed into service in 2018 partially offset by higher operations and maintenance expense as well as increased earnings at KMLP driven by revenues from the Sabine Pass expansion project that was placed into service in December 2018;
- Midstream's increase of \$123 million (10%) was primarily due to increased earnings from Gulf Coast Express, South Texas Midstream, KinderHawk, Texas intrastate natural gas pipeline operations and Cochin pipeline partially offset by decreased earnings from Hiland Midstream. Increased earnings were driven by equity earnings from the Gulf Coast Express pipeline project that was placed in service in September 2019. South Texas Midstream and KinderHawk benefited from increased drilling and production in the Eagle Ford and Haynesville basins, respectively. Texas intrastate natural gas operations were favorably impacted by higher sales margins. Increased earnings of KML's Cochin pipeline were primarily driven by higher volumes and higher tariff rates. Hiland Midstream's decreased earnings were primarily due to lower commodity prices and higher operations and maintenance expense. Overall Midstream's revenues decreased primarily due to lower commodity prices which was largely offset by corresponding decreases in costs of sales;
- West Region's increase of \$106 million (11%) was primarily due to increases in earnings from EPNG and CIG. The increase on EPNG was the result of additional capacity sales due to increased activity in the Permian Basin, partially offset by the negative impact of EPNG's 501-G rate settlement. Increased earnings on CIG were due to additional capacity sales resulting from increased activity in the Denver Julesburg basin; and
- South Region's increase of \$38 million (5%) was primarily due to contributions from ELC and SLNG resulting from three liquefaction units (part of the Elba Liquefaction project) being placed into service in the later part of 2019.

Products Pipelines

	Year Ended December 31,	
	2019	2018
	(In millions, except operating statistics)	
Revenues	\$ 1,831	\$ 1,887
Operating expenses	(684)	(748)
Other income	—	2
Earnings from equity investments	72	66
Other, net	6	2
Segment EBDA	1,225	1,209
Certain Items(a)	33	18
Adjusted Segment EBDA	\$ 1,258	\$ 1,227
Change from prior period	Increase/(Decrease)	
Adjusted revenues	\$ (56)	
Adjusted Segment EBDA	31	
Volumetric data(b)		
Gasoline(c)	1,041	1,038
Diesel fuel	368	372
Jet fuel	306	302
Total refined product volumes	1,715	1,712
Crude and condensate	651	631
Total delivery volumes	2,366	2,343

Certain Items affecting Segment EBDA

(a) Includes non-revenue Certain Item amounts of \$33 million and \$18 million in the 2019 and 2018 periods, respectively, primarily related to (i) an unfavorable adjustment of an environmental reserve (2019 period); (ii) an unfavorable adjustment of tax reserves, other than income taxes (2019 period); (iii) an increase in earnings of \$12 million as a result of property tax refunds (2018 period); and (iv) an increase in expense of \$31 million associated with a certain Pacific (SFPP) operations litigation matter (2018 period).

Other

- (b) Joint venture throughput is reported at our ownership share.
(c) Volumes include ethanol pipeline volumes.

Below are the changes in both Adjusted Segment EBDA and adjusted revenues between 2019 and 2018:

Year Ended December 31, 2019 versus Year Ended December 31, 2018

	Adjusted Segment EBDA increase/(decrease)		Adjusted revenues increase/(decrease)	
	(In millions, except percentages)			
Southeast Refined Products	\$ 16	6%	\$ (13)	(3)%
West Coast Refined Products	14	3%	16	2%
Crude & Condensate	1	—%	(59)	(8)%
Total Products Pipelines	\$ 31	3%	\$ (56)	(3)%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2019 and 2018:

- Southeast Refined Products' increase of \$16 million (6%) was due to (i) increased earnings from South East Terminals driven primarily by a gain recognized from an exchange of joint venture interests; (ii) increased earnings from Central Florida Pipeline due to higher volumes; (iii) increased equity earnings from Plantation Pipe Line as a result of increased transportation revenues driven by higher volumes and average tariff rates; and (iv) increased earnings from our Transmix processing operations primarily due to higher services revenues. The decrease in revenues was primarily

due to lower product sales volumes, with a corresponding decrease in costs of sales, resulting from a temporary shutdown of a Transmix facility in second quarter 2019;

- West Coast Refined Products' increase of \$14 million (3%) was primarily due to increased earnings on our Pacific (SFPP) operations driven by a decrease in operating expenses associated with environmental reserves and higher margins primarily due to an increase in volumes and tariff rates in 2019; and
- Crude and Condensate's increase of \$1 million (—%) was impacted by increased earnings from the Bakken Crude assets primarily due to higher crude oil gathering and delivery volumes and increased tariff rates and increased earnings from KMCC - Splitter primarily due to higher volumes driven by the Desalter project which was placed into service in May 2019, largely offset by a decrease of earnings from Kinder Morgan Crude & Condensate Pipeline due primarily to lower services revenues as a result of unfavorable rates on contract renewals, contract expirations and a decrease in recognition of deficiency revenue.

Terminals

	Year Ended December 31,	
	2019	2018
	(In millions, except operating statistics)	
Revenues	\$ 2,034	\$ 2,027
Operating expenses	(888)	(823)
Gain (loss) on divestitures and impairments, net	342	(54)
Earnings from equity investments	23	22
Other, net	(5)	3
Segment EBDA	1,506	1,175
Certain Items(a)(b)	(332)	34
Adjusted Segment EBDA	\$ 1,174	\$ 1,209
	Increase/(Decrease)	
Change from prior period		
Adjusted revenues	\$ 9	
Adjusted Segment EBDA	(35)	
Volumetric data		
Liquids tankage capacity available for service (MMBbl)	89.0	88.8
Liquids utilization %(c)	94.0%	94.9%
Bulk transload tonnage (MMtons)	59.4	64.2

Certain Items affecting Segment EBDA

- (a) Includes revenue Certain Item amount of \$(2) million for 2018.
- (b) Includes non-revenue Certain Item amounts of \$(332) million and \$36 million for 2019 and 2018, respectively, primarily related to (i) a gain of \$339 million on the sale of KML (2019 period); (ii) a loss on impairment related to our Staten Island terminal (2018 period); and (iii) net hurricane insurance recoveries (2018 period).

Other

- (c) The ratio of our tankage capacity in service to tankage capacity available for service.

Below are the changes in both Adjusted Segment EBDA and adjusted revenues between 2019 and 2018:

Year Ended December 31, 2019 versus Year Ended December 31, 2018

	Adjusted Segment EBDA increase/(decrease)		Adjusted revenues increase/(decrease)	
	(In millions, except percentages)			
Alberta Canada	\$ (18)	(13)%	\$ 6	3%
Mid Atlantic	(8)	(13)%	(9)	(8)%
Gulf Central	(6)	(10)%	(6)	(6)%
Gulf Liquids	3	1%	21	5%
All others (including intrasegment eliminations)	(6)	(1)%	(3)	—%
Total Terminals	\$ (35)	(3)%	\$ 9	—%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2019 and 2018:

- decrease of \$18 million (13%) from our Alberta Canada terminals primarily due to an increase in operating expenses associated with lease fees at our Edmonton South Terminal following the TMPL Sale and the impact of the sale of KML, partially offset by an increase in earnings due to the commencement of operations at KML's Base Line Terminal joint venture;
- decrease of \$8 million (13%) from our Mid Atlantic terminals primarily due to lower coal volumes at our Pier IX facility;
- decrease of \$6 million (10%) from our Gulf Central terminals primarily related to the termination of a customer contract in August 2018 at our Deer Park Rail Terminal and an unfavorable impact resulting from certain tanks being temporarily out of service for scheduled inspections and repairs at Battleground Oil Specialty Terminal Company LLC; and
- increase of \$3 million (1%) from our Gulf Liquids terminals primarily driven by higher volumes and associated ancillary fees, annual rate escalations on existing storage contracts and a customer rebate adversely impacting revenue recognized in the prior comparable period partially offset by higher operating costs and Ad Valorem expenses.

	Year Ended December 31,	
	2019	2018
	(In millions, except operating statistics)	
Revenues	\$ 1,219	\$ 1,255
Operating expenses	(496)	(453)
Loss on divestitures and impairments, net	(76)	(79)
Other expense	(1)	—
Earnings from equity investments	35	36
Segment EBDA	681	759
Certain Items(a)(b)	26	148
Adjusted Segment EBDA	\$ 707	\$ 907
Change from prior period	Increase/(Decrease)	
Adjusted revenues	\$ (175)	
Adjusted Segment EBDA	(200)	
Volumetric data		
SACROC oil production	23.9	24.4
Yates oil production	7.2	7.4
Katz and Goldsmith oil production	3.8	4.6
Tall Cotton oil production	2.3	2.4
Total oil production, net (MBbl/d)(c)	37.2	38.8
NGL sales volumes, net (MBbl/d)(c)	10.1	10.0
CO ₂ production, net (Bcf/d)	0.6	0.6
Realized weighted-average oil price per Bbl	\$ 49.49	\$ 57.83
Realized weighted-average NGL price per Bbl	\$ 23.49	\$ 32.21

Certain Items affecting Segment EBDA

- (a) Includes revenue Certain Item amounts of \$(49) million and \$90 million for 2019 and 2018, respectively, primarily related to unrealized gains and losses associated with derivative contracts used to hedge forecasted commodity sales.
- (b) Includes non-revenue Certain Item amounts of \$75 million and \$58 million for 2019 and 2018, respectively, primarily related to oil and gas property impairments (2019 and 2018 periods) and an increase in earnings of \$21 million as a result of a severance tax refund (2018 period).

Other

- (c) Net of royalties and outside working interests.

Below are the changes in both Adjusted Segment EBDA and adjusted revenues between 2019 and 2018:

Year Ended December 31, 2019 versus Year Ended December 31, 2018

	Adjusted Segment EBDA increase/(decrease)		Adjusted revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing activities	\$ (194)	(32)%	\$ (185)	(19)%
Source and Transportation activities	(6)	(2)%	(1)	—%
Intrasegment eliminations	—	—%	11	33%
Total CO ₂	\$ (200)	(22)%	\$ (175)	(13)%

The changes in Segment EBDA for our CO₂ business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2019 and 2018:

- decrease of \$194 million (32%) from our Oil and Gas Producing activities primarily due to decreased revenues of \$185 million driven by lower crude oil (including the Midland to Cushing differential) and NGL prices which reduced revenues by \$159 million, and lower volumes which reduced revenues by \$26 million; and
- decrease of \$6 million (2%) from our Source and Transportation activities primarily due to lower CO₂ sales driven by lower contract sales prices of \$10 million and higher operating expenses partially offset by higher CO₂ sales volumes of \$9 million.

General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Year Ended December 31,	
	2019	2018
	(In millions)	
General and administrative (GAAP)	\$ (590)	\$ (601)
Corporate (charges) benefit	(21)	13
Certain Items(a)	13	24
General and administrative and corporate charges(b)	\$ (598)	\$ (564)
Interest, net (GAAP)	\$ (1,801)	\$ (1,917)
Certain Items(c)	(15)	26
Interest, net(b)	\$ (1,816)	\$ (1,891)
Net income attributable to noncontrolling interests (GAAP)	\$ (49)	\$ (310)
Certain Items(d)	(4)	240
Net income attributable to noncontrolling interests(b)	\$ (53)	\$ (70)

Certain Items

- (a) 2019 amount includes: (i) an increase in asset sale related costs of \$15 million; (ii) an increase in expense of \$13 million related to a litigation matter; and (iii) an increase in earnings of \$19 million associated with a non-cash fair value adjustment on the Pembina common stock. 2018 amount includes: (i) an increase in expense of \$10 million associated with an environmental reserve adjustment; (ii) an increase in asset sale related costs of \$10 million; (iii) an increase in expense of \$9 million related to certain corporate litigation matters; and (iv) a decrease in expense of \$12 million related to an adjustment of tax reserves, other than income taxes.
- (b) Amounts are adjusted for Certain Items.
- (c) 2019 and 2018 amounts include: (i) decreases in interest expense of \$29 million and \$32 million, respectively, related to non-cash debt fair value adjustments associated with acquisitions and (ii) increases of \$13 million and \$9 million, respectively, in interest expense related to non-cash mismatches between the change in fair value of interest rate swaps and change in fair value of hedged debt. 2018 amount also includes an increase in interest expense of \$47 million related to the write-off of capitalized KML credit facility fees.
- (d) 2018 amount is primarily associated with the noncontrolling interests portion of the \$596 million gain on the TMPL Sale.

General and administrative expenses and corporate charges adjusted for Certain Items increased \$34 million in 2019 when compared to 2018 primarily due to higher pension expenses of \$44 million partially offset by lower expenses of \$17 million due to the TMPL Sale.

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 of interest income adjusted for Certain Items decreased \$75 million in 2019 when compared to 2018 primarily due to lower average debt balances and greater capitalized interest, partially offset by higher LIBOR rates which impacted our interest rate swap agreements and impact of 2018 Canadian operations, which includes interest income on TMPL proceeds.

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, 2019 and 2018, approximately 27% and 31%, 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. 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. Net income attributable to noncontrolling interests adjusted for Certain Items decreased \$17 million in 2019 compared to 2018 primarily due to the TMPL and KML Sales.

Income Taxes

Year Ended December 31, 2019 versus Year Ended December 31, 2018

Our income tax expense for the year ended December 31, 2019 is approximately \$926 million, as compared with income tax expense of \$587 million for the same period of 2018. The \$339 million increase in income tax expense in 2019 as compared to 2018 is primarily due to the KML and U.S. Cochin Sale.

Liquidity and Capital Resources

General

As of December 31, 2019, we had \$185 million of "Cash and cash equivalents," a decrease of \$3,095 million (94%) from December 31, 2018. The decrease was primarily driven by a \$1.9 billion debt repayment using the proceeds from the 2018 TMPL Sale in early 2019 and \$0.9 billion paid to noncontrolling interests by KML on January 3, 2019 as a return of capital. Additionally, as of December 31, 2019, we had borrowing capacity of approximately \$3.9 billion under our \$4 billion revolving credit facility. We believe our cash position, remaining borrowing capacity on our credit facility (discussed below in "*Short-term Liquidity*"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

We have consistently generated substantial cash flow from operations, providing a source of funds of \$4,748 million and \$5,043 million in 2019 and 2018, respectively. The year-to-year decrease is discussed below in "*Cash Flows—Operating Activities*." Generally, 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. We also generally expect that our short-term liquidity needs will be met primarily through retained cash from operations, short-term borrowings or by issuing new long-term debt to refinance certain of our maturing long-term debt obligations. Moreover, as a result of our current common stock dividend policy and our continued focus on disciplined capital allocation, we do not expect the need to access the equity capital markets to fund our growth projects for the foreseeable future.

On December 16, 2019, we closed on the KML and U.S. Cochin Sale (discussed above in "*General—KML—Sale of U.S. Portion of Cochin Pipeline and KML*"). We received cash proceeds of \$1.553 billion for the U.S. portion of the Cochin Pipeline which was used to pay down debt. KML common shareholders received 0.3068 shares of Pembina common stock for each share of KML common stock. On January 9, 2020, we sold the approximate 25 million shares of Pembina common stock that we received in the sale of KML. The after-tax proceeds of approximately \$764 million will be used to pay down debt.

Short-term Liquidity

As of December 31, 2019, our principal sources of short-term liquidity are (i) cash from operations; and (ii) our \$4.0 billion revolving credit facility and associated commercial paper program. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes, and as a backup to our commercial paper program. Letters of credit and commercial paper borrowings reduce borrowings allowed under our credit facility (see Note 9 "*Debt—Credit Facility and Restrictive Covenants*" to our consolidated financial statements). We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations.

As of December 31, 2019, our \$2,477 million of short-term debt consisted primarily of (i) \$2,184 million of senior notes that mature in the next twelve months; (ii) \$100 million of a preferred interest in the general partner of KMP; and (iii) \$37 million outstanding under our commercial paper program. During 2019, we repaid approximately \$2.8 billion of maturing debt with cash proceeds received from the TMPL Sale and the sale of the U.S. portion of the Cochin Pipeline. Otherwise, as our debt becomes due, we intend to fund our short-term debt primarily through credit facility borrowings, commercial paper borrowings, the proceeds from the sale of the Pembina common stock, and/or issuing new long-term debt. Our short-term debt balance as of December 31, 2018 was \$3,388 million.

We had working capital (defined as current assets less current liabilities) deficits of \$1,862 million and \$1,835 million as of December 31, 2019 and 2018, respectively. 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 \$27 million (1%) unfavorable change from year-end 2018 was primarily due to: (i) a decrease in cash and cash equivalents of \$3,095 million, substantially offset by (i) \$925 million of marketable securities representing the Pembina common stock we received from the sale of KML; (ii) a decrease in short-term debt of \$911 million; (iii) a decrease in distributions payable of \$876 million related to a return of capital to KML noncontrolling interests; and (iv) a net decrease in accounts payable, accrued interest and accrued taxes. 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.

Certain of our wholly owned subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

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, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn reduce our cash flows and limit our ability to pursue acquisition or expansion opportunities.

As of December 31, 2019, 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, 2019.

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. Furthermore, through January 2019, we had repurchased approximately 29 million shares of our Class P common stock under a \$2 billion share buy-back program authorized by our board of directors in December 2017 that we funded through retained cash. For more information on our equity buy-back program and our equity distribution agreement, see Note 11 “Stockholders’ Equity” to our consolidated financial statements.

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 have issued 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 we each guarantee each other's debt. See Note 20 "Guarantee of Securities of Subsidiaries" to our consolidated financial statements. As of December 31, 2019 and 2018, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was \$30,883 million and \$33,205 million, respectively. For more information regarding our debt-related transactions in 2019, see Note 9 "Debt" to our consolidated financial statements.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping 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 2019, 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."

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures (which we also refer to as discretionary capital expenditures). Expansion capital expenditures are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF (see "—Results of Operations—Non-GAAP Financial Measures—Reconciliation of Net Income Available to Common Stockholders (GAAP) to Adjusted Earnings to DCF"). With respect to our oil and gas producing activities, we classify a capital expenditure as an expansion capital expenditure if it is expected to increase capacity or throughput (i.e., production capacity) from the capacity or throughput immediately prior to the making or acquisition of such additions or improvements. Maintenance capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of maintenance capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those maintenance 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 maintenance 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 maintenance/sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as maintenance 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 maintenance capital expenditures are.

Our capital expenditures for the year ended December 31, 2019, and the amount we expect to spend for 2020 to sustain our assets and grow our business are as follows (in millions):

	2019	Expected 2020
Sustaining capital expenditures(a)(b)	\$ 688	\$ 716
Discretionary capital investments(b)(c)(d)	\$ 2,777	\$ 2,395

(a) 2019 and Expected 2020 amounts include \$114 million and \$128 million, respectively, for our proportionate share of (i) certain equity investee's; (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures.

(b) 2019 excludes \$142 million of net changes from accrued capital expenditures, contractor retainage, and other.

(c) 2019 amount includes \$1,223 million of our contributions to certain unconsolidated joint ventures for capital investments and small acquisitions.

- (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

	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)	\$ 33,360	\$ 2,477	\$ 4,922	\$ 5,175	\$ 20,786
Interest payments(b)	22,550	1,779	3,194	2,742	14,835
Lease obligations(c)	467	55	83	62	267
Pension and OPEB plans(d)	851	78	40	38	695
Transportation, volume and storage agreements(e)	768	166	273	167	162
Other obligations(f)	477	96	146	90	145
Total	\$ 58,473	\$ 4,651	\$ 8,658	\$ 8,274	\$ 36,890
Other commercial commitments:					
Standby letters of credit(g)	\$ 135	\$ 62	\$ 73	\$ —	\$ —
Capital expenditures(h)	\$ 439	\$ 439	\$ —	\$ —	\$ —

(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, 2019.

(c) Represents commitments pursuant to the terms of operating lease agreements as of December 31, 2019.

(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 to funded plans in 2020 and estimated benefit payments for unfunded plans in all years.

(e) Primarily represents transportation agreements of \$315 million, NGL volume agreements of \$273 million and storage agreements for capacity of \$156 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, 2019.

(g) The \$135 million in letters of credit outstanding as of December 31, 2019 consisted of the following (i) letters of credit totaling \$46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (ii) \$33 million under seven letters of credit for insurance purposes; (iii) a \$24 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; and (iv) a combined \$32 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, 2019.

Cash Flows

Operating Activities

Cash provided by operating activities decreased \$295 million in 2019 compared to 2018 primarily due to:

- a \$481 million decrease in cash resulting from net \$372 million income tax payments in the 2019 period primarily for foreign income tax associated with the TMPL Sale compared to net \$109 million income tax refunds that we received in the 2018 period; partially offset by,

- a \$186 million increase in cash primarily driven by a reduction in litigation payments resulting from rate case refunds made to EPNG shippers in 2018, offset partially by a decrease in cash from other operating activities in the 2019 period compared to the 2018 period.

Investing Activities

Cash used in investing activities increased \$1,646 million in 2019 compared to 2018 primarily due to:

- a \$3,026 million decrease in cash reflecting proceeds received in the 2018 period from the TMPL Sale, net of cash disposed. See Note 3 “*Divestitures*” to our consolidated financial statements for further information regarding this transaction; and
- an \$866 million increase in cash used for contributions to equity investments driven by contributions made in 2019 to MEP, Citrus Corporation and FEP to fund our proportionate share of these equity investees’ 2019 maturing debt obligations, and higher contributions to Gulf Coast Express Pipeline LLC and Permian Highway Pipeline LLC to fund construction in the 2019 period compared with the 2018 period; partially offset by,
- the \$1,527 million increase in cash resulting from proceeds received from the KML and U.S. Cochin Sale, net of cash disposed, in 2019. See Note 3 “*Divestitures*” to our consolidated financial statements for further information regarding this transaction; and
- a \$634 million decrease in capital expenditures in the 2019 period over the comparative 2018 period primarily due to no expenditures in 2019 for the TMEP, and to a lesser extent lower expenditures in our Natural Gas Pipelines business segment.

Financing Activities

Cash used in financing activities increased \$4,361 million in 2019 compared to 2018 primarily due to:

- a \$3,316 million net increase in cash used related to debt activity as a result of \$3,198 million of net debt payments in the 2019 period compared to \$118 million of net debt issuances in the 2018 period. See Note 9 “*Debt*” to our consolidated financial statements for further information regarding our debt activity;
- an \$879 million decrease in cash resulting from the distribution of the TMPL Sale proceeds to noncontrolling interests in the 2019 period; and
- a \$545 million increase in dividend payments to our common shareholders; partially offset by,
- a \$271 million decrease in cash used due to fewer common shares repurchased under our common share buy-back program in the 2019 period compared to the 2018 period; and
- a \$156 million decrease in cash used to pay mandatory convertible preferred shareholders in the 2018 period.

Dividends and Stock Buy-back Program

KMI Common Stock Dividends

The table below reflects the declaration of common stock dividends of \$1.00 per common share for 2019.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2019	\$0.25	April 17, 2019	April 30, 2019	May 15, 2019
June 30, 2019	0.25	July 17, 2019	July 31, 2019	August 15, 2019
September 30, 2019	0.25	October 16, 2019	October 31, 2019	November 15, 2019
December 31, 2019	0.25	January 22, 2020	February 3, 2020	February 18, 2020

We expect to continue to return additional value to our shareholders in 2020 through our previously announced dividend increase. We plan to increase our dividend to \$1.25 per common share in 2020, a growth rate of 25%.

The actual amount of common stock 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 in declaring dividends.

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

Stock Buy-back Program

On July 19, 2017, our board of directors approved a \$2 billion common share buy-back program that began in December 2017. During the years ended December 31, 2019, 2018 and 2017, we repurchased approximately 0.1 million, 15 million and 14 million, respectively, of our Class P shares for approximately \$2 million, \$273 million and \$250 million, respectively. Since December 2017, in total, we have repurchased approximately 29 million of our Class P shares under the program at an average price of approximately \$18.18 per share for approximately \$525 million.

Noncontrolling Interests

The caption "Noncontrolling interests" in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2019	2018
KML(a)	\$ —	\$ 514
Others	344	339
	\$ 344	\$ 853

(a) On December 16, 2019, we completed the sale of all the outstanding common equity of KML, including our 70% interest, to Pembina. See Note 3 for more information.

KML Distributions

During the year ended December 31, 2019, KML paid dividends of \$17 million on its restricted voting shares owned by the public. KML also paid dividends to the public on its Series 1 and Series 3 Preferred Shares of \$22 million for the year ended December 31, 2019. In addition, on January 3, 2019 KML paid a return of capital of \$879 million to its restricted voting shares owned by the public.

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 are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we manage these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks 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 which 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.

The credit ratings of the primary parties from whom we transact in energy commodity derivative contracts (based on contract market values) are as follows (credit ratings per Standard & Poor's Rating Service):

	Credit Rating
ING	A+
Citibank	A+
Wells Fargo	A+
Macquarie	A+
Societe Generale	A

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 (in millions):

Commodity derivative	As of December 31,	
	2019	2018
Crude oil	\$ 113	\$ 97
Natural gas	8	12
NGL	7	6
Total	\$ 128	\$ 115

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. 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 the preferred interest in KMP held by KMGP that was redeemed on January 15, 2020, and sensitivity to interest rates (in millions):

	December 31, 2019		December 31, 2018	
	Carrying value	Estimated fair value(c)	Carrying value	Estimated fair value(c)
Fixed rate debt(a)	\$ 33,943	\$ 37,588	\$ 36,480	\$ 36,647
Variable rate debt	\$ 449	\$ 428	\$ 844	\$ 822
Notional principal amount of variable-to-fixed interest rate swap agreements	(250)		—	
Notional principal amount of fixed-to-variable interest rate swap agreements	8,725		10,575	
Debt balances subject to variable interest rates(b)	\$ 8,924		\$ 11,419	

(a) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2019 and 2018, would result in changes of approximately \$1,548 million and \$1,638 million, respectively, in the fair values of these instruments.

(b) A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 53 and 52 basis points, respectively, in 2019 and 2018) when applied to our outstanding balance of variable rate debt as of December 31, 2019 and 2018, including adjustments for the notional swap amounts described above, would result in changes of approximately \$47 million and \$59 million, respectively, in our 2019 and 2018 annual pre-tax earnings.

(c) Fair values were determined using Level 2 inputs.

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. Since the fair value of fixed rate debt varies with changes in the market rate of interest, swap agreements are entered into to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of the fixed rate debt due to market rate changes.

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, 2019, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 27% 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.

LIBOR Phase Out

Amounts drawn under our revolving credit facility may bear interest rates in relation to LIBOR, depending on our selection of repayment options, and certain of our outstanding interest rate swap agreements have a floating interest rate in relation to one-month LIBOR or three-month LIBOR. In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of 2021. The Alternative Reference Rates Committee, a steering committee consisting of large U.S. financial institutions convened by the U.S. Federal Reserve Board and the Federal Reserve Bank of New York, has recommended replacing LIBOR with the Secured Overnight Financing Rate (SOFR), a new index supported by short-term Treasury repurchase agreements. Although there have been some transactions utilizing SOFR, it is unknown whether this alternative reference rate will attain market acceptance as a replacement for LIBOR. The agreement governing our revolving credit facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our lenders agree upon a replacement rate based on the then-prevailing market convention for similar agreements. The International Swaps and Derivatives Association is developing parameters for replacement rates that

would apply upon cessation of LIBOR and has indicated plans to publish a protocol to enable market participants to include the replacement rates in existing swap agreements.

We currently do not expect the transition from LIBOR to have a material impact on us. However, if clear market standards and replacement methodologies have not developed as of the time LIBOR becomes unavailable, we may have difficulty reaching agreement on acceptable replacement rates under our revolving credit facility and our interest rate swap agreements. If we are unable to negotiate replacement rates on favorable terms, it could have a material adverse effect on our earnings and cash flows.

Foreign Currency Risk

As of December 31, 2019, we had a notional principal amount of \$1,358 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.

The information required in this Item 8 is in this report as set forth in the "Index to Financial Statements" on page 68.

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, 2019, 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 and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, 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, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019, 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 2019 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

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 2020 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2020.

Item 11. Executive Compensation.

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2020 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2020.

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 2020 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2020.

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 2020 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2020.

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 2020 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2020.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) (1) Financial Statements and (2) Financial Statement Schedules

See "Index to Financial Statements" set forth on Page 68.

(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 October 20, 2017 (File No. 001-35081))
4.1 *	Form of certificate representing Class P common shares 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 *	Form of Senior Indenture between Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.6 *	Form of Senior Note of Kinder Morgan Kansas, Inc. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Kansas, Inc.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102963))
4.7 *	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))
4.8 *	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))
4.9 *	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))
4.10 *	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))
4.11 *	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))
4.12 *	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))
4.13 *	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))

Exhibit Number	Description
4.14 *	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))
4.15 *	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))
4.16 *	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))
4.17 *	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))
4.18 *	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))
4.19 *	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))
4.20 *	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))
4.21 *	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))
4.22 *	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 6.85% Senior Notes due 2020 (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, 2009 (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 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))
4.24 *	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))
4.25 *	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))
4.26 *	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))

Exhibit Number	Description
4.27 *	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))
4.28 *	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))
4.29 *	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))
4.30 *	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))
4.31 *	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))
4.32 *	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))
4.33 *	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))
4.34 *	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))
4.35 *	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))
4.36	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.
4.37	Description of Capital Stock of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934
4.38	Description of Debt Securities of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934
10.1 *	KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))
10.2 *	Amendment No. 1 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed on January 24, 2017 (File No. 001-35081))
10.3 *	Amendment No. 2 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (File No. 001-35081))
10.4 *	Amendment No. 3 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed on January 22, 2019 (File No. 001-35081))
10.5 *	2015 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 4.6 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))

Exhibit Number	Description
10.6 *	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))
10.7 *	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))
10.8 *	Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
10.9 *	2015 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.6 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
10.10 *	2011 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081))
10.11 *	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))
10.12 *	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.4 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
10.13 *	Amendment No. 1 to Amended and Restated Incentive Plan of KMI (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed January 24, 2017 (File No. 001-35081))
10.14 *	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))
10.15	Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2019
21.1	Subsidiaries of KMI
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, 2019, 2018, and 2017; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2019, 2018, and 2017; (iii) our Consolidated Balance Sheets as of December 31, 2019 and 2018; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2019, 2018, and 2017; (v) our Consolidated Statements of Stockholders' Equity as of and for the years ended December 31, 2019, 2018, and 2017; 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.

**KINDER MORGAN, INC. AND SUBSIDIARIES
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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, 2019 and 2018 and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by 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 \$21.5 billion as of December 31, 2019. Management evaluates goodwill for impairment on May 31 of each year, or more frequently to the extent events or conditions indicate a risk of possible impairment during the interim periods subsequent to the annual impairment test. Management estimates fair value based primarily 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 there was 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 audit evidence related to management's forecasted EBITDA and estimates of enterprise value to EBITDA multiples of comparable companies for each reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

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 the development of the fair value estimate of the Company's reporting units. These procedures also included, among others, testing management's process for developing the fair value estimate; evaluating the appropriateness of the market approach model; and evaluating the significant assumptions used by management, including management's forecasted EBITDA and estimates of enterprise value to EBITDA multiples of comparable companies for each reporting unit. Evaluating management's significant assumptions related to forecasted EBITDA and estimated enterprise value to 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 Company's market approach model and certain significant assumptions, including the estimated enterprise value to EBITDA multiples of comparable companies for each reporting unit.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 11, 2020

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,		
	2019	2018	2017
Revenues			
Services	\$ 8,198	\$ 7,955	\$ 7,885
Commodity sales	4,811	5,987	5,654
Other	200	202	166
Total Revenues	13,209	14,144	13,705
Operating Costs, Expenses and Other			
Costs of sales	3,263	4,421	4,345
Operations and maintenance	2,591	2,522	2,472
Depreciation, depletion and amortization	2,411	2,297	2,261
General and administrative	590	601	688
Taxes, other than income taxes	426	345	398
(Gain) loss on divestitures and impairments, net	(942)	167	13
Other income, net	(3)	(3)	(1)
Total Operating Costs, Expenses and Other	8,336	10,350	10,176
Operating Income	4,873	3,794	3,529
Other Income (Expense)			
Earnings from equity investments	101	617	428
Amortization of excess cost of equity investments	(83)	(95)	(61)
Interest, net	(1,801)	(1,917)	(1,832)
Other, net	75	107	97
Total Other Expense	(1,708)	(1,288)	(1,368)
Income Before Income Taxes	3,165	2,506	2,161
Income Tax Expense	(926)	(587)	(1,938)
Net Income	2,239	1,919	223
Net Income Attributable to Noncontrolling Interests	(49)	(310)	(40)
Net Income Attributable to Kinder Morgan, Inc.	2,190	1,609	183
Preferred Stock Dividends	—	(128)	(156)
Net Income Available to Common Stockholders	\$ 2,190	\$ 1,481	\$ 27
Class P Shares			
Basic and Diluted Earnings Per Common Share	\$ 0.96	\$ 0.66	\$ 0.01
Basic and Diluted Weighted Average Common Shares Outstanding	2,264	2,216	2,230

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,		
	2019	2018	2017
Net income	\$ 2,239	\$ 1,919	\$ 223
Other comprehensive income (loss), net of tax			
Change in fair value of hedge derivatives (net of tax benefit (expense) of \$52, \$(34), and \$(82), respectively)	(177)	111	145
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of \$(2), \$(25) and \$97, respectively)	6	84	(171)
Foreign currency translation adjustments (net of tax expense of \$27, \$16 and \$56, respectively)	108	141	101
Benefit plan adjustments (net of tax expense of \$23, \$11 and \$27, respectively)	77	2	40
Total other comprehensive income	14	338	115
Comprehensive income	2,253	2,257	338
Comprehensive income attributable to noncontrolling interests	(66)	(328)	(86)
Comprehensive income attributable to KMI	\$ 2,187	\$ 1,929	\$ 252

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,	
	2019	2018
ASSETS		
Current assets		
Cash and cash equivalents	\$ 185	\$ 3,280
Restricted deposits	24	51
Marketable securities at fair value	925	—
Accounts receivable, net	1,370	1,498
Fair value of derivative contracts	84	260
Inventories	371	385
Other current assets	279	248
Total current assets	3,238	5,722
Property, plant and equipment, net	36,419	37,897
Investments	7,759	7,481
Goodwill	21,451	21,965
Other intangibles, net	2,676	2,880
Deferred income taxes	857	1,566
Deferred charges and other assets	1,757	1,355
Total Assets	\$ 74,157	\$ 78,866
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	\$ 2,477	\$ 3,388
Accounts payable	914	1,337
Distributions payable to KML noncontrolling interests	—	876
Accrued interest	548	579
Accrued taxes	364	483
Other current liabilities	797	894
Total current liabilities	5,100	7,557
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	30,883	33,205
Debt fair value adjustments	1,032	731
Total long-term debt	31,915	33,936
Other long-term liabilities and deferred credits	2,253	2,176
Total long-term liabilities and deferred credits	34,168	36,112
Total Liabilities	39,268	43,669
Commitments and contingencies (Notes 9, 13, 17 and 18)		
Redeemable Noncontrolling Interest	803	666
Stockholders' Equity		
Class P shares, \$0.01 par value, 4,000,000,000 shares authorized, 2,264,936,054 and 2,262,165,783 shares, respectively, issued and outstanding	23	23
Additional paid-in capital	41,745	41,701
Accumulated deficit	(7,693)	(7,716)
Accumulated other comprehensive loss	(333)	(330)
Total Kinder Morgan, Inc.'s stockholders' equity	33,742	33,678
Noncontrolling interests	344	853
Total Stockholders' Equity	34,086	34,531
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	\$ 74,157	\$ 78,866

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,		
	2019	2018	2017
Cash Flows From Operating Activities			
Net income	\$ 2,239	\$ 1,919	\$ 223
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,411	2,297	2,261
Deferred income taxes	717	405	2,073
Amortization of excess cost of equity investments	83	95	61
Change in fair market value of derivative contracts	(22)	77	40
(Gain) loss on divestitures and impairments, net (Note 4)	(942)	167	13
Earnings from equity investments	(101)	(617)	(428)
Distributions of equity investment earnings	590	499	426
Changes in components of working capital, net of the effects of acquisitions and dispositions			
Accounts receivable, net	105	(50)	(78)
Income tax receivable	—	137	7
Inventories	4	15	(90)
Other current assets	93	(16)	(25)
Accounts payable	(198)	21	73
Accrued interest, net of interest rate swaps	(43)	(22)	10
Accrued taxes	(142)	241	(37)
Accrued contingencies and other current liabilities	(69)	73	138
Other, net	23	(198)	(66)
Net Cash Provided by Operating Activities	4,748	5,043	4,601
Cash Flows From Investing Activities			
Proceeds from the KML and U.S. Cochin Sale, net of cash disposed (Note 3)	1,527	—	—
Proceeds from the TMPL Sale, net of cash disposed and working capital adjustments (Note 3)	(28)	2,998	—
Acquisitions of assets and investments	(79)	(39)	(4)
Capital expenditures	(2,270)	(2,904)	(3,188)
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	110	104	118
Contributions to investments	(1,299)	(433)	(684)
Distributions from equity investments in excess of cumulative earnings	333	237	374
Loans to related parties	(31)	(31)	(23)
Other, net	23	—	4
Net Cash Used in Investing Activities	(1,714)	(68)	(3,403)
Cash Flows From Financing Activities			
Issuances of debt	8,036	14,751	8,868
Payments of debt	(11,224)	(14,591)	(11,064)
Debt issue costs	(10)	(42)	(70)
Cash dividends - common shares (Note 11)	(2,163)	(1,618)	(1,120)
Cash dividends - preferred shares (Note 11)	—	(156)	(156)
Repurchases of common shares	(2)	(273)	(250)
Contributions from investment partner	148	181	485
Contributions from noncontrolling interests - net proceeds from KML IPO (Note 3)	—	—	1,245
Contributions from noncontrolling interests - net proceeds from KML preferred share issuances (Note 11)	—	—	420
Contributions from noncontrolling interests - other	3	19	12
Distributions to investment partner	(11)	—	—
Distribution to noncontrolling interests - KML distribution of the TMPL Sale proceeds	(879)	—	—
Distributions to noncontrolling interests - other	(55)	(78)	(42)
Other, net	(28)	(17)	(9)
Net Cash Used in Financing Activities	(6,185)	(1,824)	(1,681)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	29	(146)	22
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	(3,122)	3,005	(461)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3,331	326	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	\$ 209	\$ 3,331	\$ 326

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

	Year Ended December 31,		
	2019	2018	2017
Cash and Cash Equivalents, beginning of period	\$ 3,280	\$ 264	\$ 684
Restricted Deposits, beginning of period	51	62	103
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3,331	326	787
Cash and Cash Equivalents, end of period	185	3,280	264
Restricted Deposits, end of period	24	51	62
Cash, Cash Equivalents, and Restricted Deposits, end of period	209	3,331	326
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	\$ (3,122)	\$ 3,005	\$ (461)
Noncash Investing and Financing Activities			
Marketable securities obtained as consideration for divestiture (Note 3)	\$ 892	\$ —	\$ —
ROU assets and operating lease obligations recognized (Note 17)	399		
Decrease in noncontrolling interests for distribution accrual	—	905	—
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,860	1,879	1,854
Cash paid (refunded) during the period for income taxes, net	372	(109)	(140)

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

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

	Preferred stock		Common stock		Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
	Issued shares	Par value	Issued shares	Par value						
Balance at December 31, 2016	2	\$ —	2,230	\$ 22	\$ 41,739	\$ (6,669)	\$ (661)	\$ 34,431	\$ 371	\$34,802
Repurchases of shares			(14)		(250)			(250)		(250)
Restricted shares			1		65			65		65
Net income						183		183	40	223
KML IPO					314		51	365	684	1,049
KML preferred share issuance								—	419	419
Reorganization of foreign subsidiaries					38			38		38
Distributions								—	(48)	(48)
Contributions								—	18	18
Preferred stock dividends						(156)		(156)		(156)
Common stock dividends						(1,120)		(1,120)		(1,120)
Sale and deconsolidation of interest in Deeprock Development, LLC								—	(30)	(30)
Other					3	8		11	(12)	(1)
Other comprehensive income							69	69	46	115
Balance at December 31, 2017	2	—	2,217	22	41,909	(7,754)	(541)	33,636	1,488	35,124
Impact of adoption of ASU (Note 11)						175	(109)	66		66
Balance at January 1, 2018	2	—	2,217	22	41,909	(7,579)	(650)	33,702	1,488	35,190
Repurchases of shares			(15)		(273)			(273)		(273)
Mandatory conversion of preferred shares	(2)		58	1	(1)			—		—
Restricted shares			2		65			65		65
Net income						1,609		1,609	310	1,919
Distributions								—	(997)	(997)
Contributions								—	33	33
Preferred stock dividends						(128)		(128)		(128)
Common stock dividends						(1,618)		(1,618)		(1,618)
Other					1			1	1	2
Other comprehensive income							320	320	18	338
Balance at December 31, 2018	—	—	2,262	23	41,701	(7,716)	(330)	33,678	853	34,531
Impact of adoption of ASU (Note 14)						(4)		(4)		(4)
Balance at January 1, 2019	—	—	2,262	23	41,701	(7,720)	(330)	33,674	853	34,527
Repurchases of shares					(2)			(2)		(2)
Restricted shares			3		46			46		46
Net income						2,190		2,190	49	2,239
Distributions								—	(55)	(55)
Contributions								—	3	3
Common stock dividends						(2,163)		(2,163)		(2,163)
Sale of interest in KML							68	68	(503)	(435)
Other								—	1	1

Other comprehensive loss							(71)		(71)		(4)	(75)
Balance at December 31, 2019	—	\$ —	2,265	\$ 23	\$ 41,745	\$ (7,693)	\$ (333)	\$ 33,742	\$ 344	\$34,086		

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

KINDER MORGAN, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are one of the largest energy infrastructure companies in North America and 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, crude oil, condensate, CO₂ and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, 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.

For a discussion of significant Accounting Standards Updates (ASU) we adopted on January 1, 2019 and 2018, see below “ — Revenue Recognition” and Notes 10, 11, 14, 15 and 17.

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 as it relates 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 and cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions.

Accounts Receivable, net

The amounts reported as “Accounts receivable, net” on our accompanying consolidated balance sheets as of December 31, 2019 and 2018 primarily consist of amounts due from customers net of the allowance for doubtful accounts.

Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. Generally, we make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and we record

adjustments as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved.

The allowance for doubtful accounts was \$9 million and \$3 million as of December 31, 2019 and 2018, respectively.

Inventories

Our inventories consist of materials and supplies and products such as NGL, crude oil, condensate, refined petroleum products, transmix and natural gas. 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.

We generally compute depreciation using either the straight-line method based on estimated economic lives or the composite depreciation method, which applies a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 1.01% to 23.0% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances, estimated production life of the oil or gas field served by the asset, contract term for assets on leased or customer property and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When these assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could 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.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method, 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.

We engage in enhanced recovery techniques in which CO₂ is injected into certain producing oil reservoirs. In some cases, the cost of the CO₂ associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO₂ associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO₂ 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 gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our bulk and liquids terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A 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 sales proceeds received or the market value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset. For our pipeline system assets under the composite method of depreciation, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. Gains and losses are booked for FERC-approved operating unit sales and land sales and are recorded to income or expense accounts in accordance with regulatory accounting guidelines.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. 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. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to 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.

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. 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 and Other Intangibles 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. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

In addition to our annual goodwill impairment test, 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. Because the impairment test for long-lived assets held in use is based on 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 undiscounted cash flows, we typically use discounted cash flow analyses to determine if an impairment is required.

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 total proved and risk-adjusted probable reserves.

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 total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. 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.

Equity Method of Accounting and Basis Differences

We account for investments which we do not control, but do have the ability to exercise significant influence using the equity method of accounting. 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 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. This

test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

We evaluate goodwill for impairment on May 31 of each year. For this purpose, prior to the TMPL Sale we had seven reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO₂; (vi) Terminals; and (vii) Kinder Morgan Canada. Subsequent to the TMPL Sale, Kinder Morgan Canada is no longer a reporting unit. We also evaluate goodwill for impairment to the extent events or conditions indicate a risk of possible impairment during the interim periods subsequent to our annual impairment test. Generally, the evaluation of goodwill for impairment involves a two-step test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

Step 1 involves comparing the estimated fair value of each respective reporting unit to its carrying value, including goodwill. If the estimated fair value exceeds the carrying value, the reporting unit's goodwill is not considered impaired. If the carrying value exceeds the estimated fair value, step 2 must be performed to determine whether goodwill is impaired and, if so, the amount of the impairment. Step 2 involves calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill is then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeds the implied goodwill, the difference is the amount of the goodwill impairment.

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, relationships and agreements, and technology-based assets. As of both December 31, 2019 and 2018, the gross carrying amounts of these intangible assets was \$4,126 million and \$4,305 million, respectively, and the accumulated amortization was \$1,450 million and \$1,425 million, respectively, resulting in net carrying amounts of \$2,676 million and \$2,880 million, respectively. These intangible assets primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Terminals business segments.

Primarily, these contracts, relationships and agreements relate to the gathering of natural gas, and the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, petroleum coke, metals and ores. 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 effect of obsolescence, new technology, and competition.

For the years ended December 31, 2019, 2018 and 2017, the amortization expense on our intangibles totaled \$214 million, \$219 million and \$220 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2020 – 2024) is approximately \$209 million, \$209 million, \$208 million, \$203 million, and \$203 million, respectively. As of December 31, 2019, the weighted average amortization period for our intangible assets was approximately fourteen years.

Revenue Recognition

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with ASU No. 2014-09, "Revenue from Contracts with Customers" and a series of related accounting standard updates (Topic 606). The unit of account in Topic 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. Topic 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) control of the goods or services transfers to the customer and the performance obligation is satisfied.

Our customer sales contracts primarily include natural gas sales, NGL sales, crude oil sales, CO₂ sales, and transmix sales contracts, as described below. Generally, for the majority of these contracts: (i) each unit (Mcf, 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 primarily include transportation service, storage service, gathering and processing service, and terminaling service contracts, 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).

Refer to Note 15 for further information.

Revenue Recognition Policy prior to January 1, 2018

Prior to the implementation of Topic 606, we recognized revenue as services were rendered or goods were delivered and, if applicable, risk of loss had passed. We recognized natural gas, crude and NGL sales revenue when the commodity was sold to a purchaser at a fixed or determinable price, delivery had occurred and risk of loss had transferred, and collectability of the revenue was reasonably assured. Our sales and purchases of natural gas, crude and NGL were primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales, except in circumstances where we solely acted as an agent and did not have price and related risk of ownership, in which case we recognized revenue on a net basis.

For revenues associated with our firm services as previously described, the fixed-fee component of the overall rate was recognized as revenue in the period the service was provided. The per-unit charge was recognized as revenue when the volumes were delivered to the customers' agreed upon delivery point, or when the volumes were injected into/withdrawn from our storage facilities.

Revenues associated with our non-firm services as previously described, were recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements.

Revenues associated with our crude oil and refined petroleum products transportation and storage services were recorded when products were delivered and services had been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognized bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognized liquids terminal tank rental revenue ratably over the contract period. We recognized liquids terminal throughput revenue based on volumes received and volumes delivered. We recognized transmix processing revenues based on volumes processed or sold, and if applicable, when risk of loss had passed. We recognized energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of crude oil, NGL, CO₂ and natural gas production within the CO₂ business segment were recorded using the entitlement method, under which revenue was recorded when title passed based on our net interest. We recorded our entitled share of revenues based on entitled volumes and contracted sales prices. Since there was a ready market for oil and gas production, we sold the majority of our products soon after production at various locations, at which time title and risk of loss had passed to the buyer.

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 CO₂ producing activities, such as those in our CO₂ business segment, are not accounted for as costs of sales.

Operations and Maintenance

Operations and maintenance include 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 CO₂ producing activities included within operations and maintenance totaled \$382 million, \$363 million and \$342 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required in obtaining 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 recording of these accruals coincides with 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

Lessee

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 34 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.

Beginning January 1, 2019, operating ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. Operating leases in effect prior to January 1, 2019 were recognized at the present value of the remaining payments on the remaining lease term as of January 1, 2019. Leases with variable rate adjustments, such as Consumer Price Index (CPI) adjustments, were 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, while for the remainder of our agreements we have elected the practical expedient to account for lease and non-lease components as a single lease component. 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 agreements are modified.

Refer to Note 17 for further information.

Lessor

Our assets that we lease to others under operating leases primarily consist of specific facilities 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, marine vessels and gas equipment and pipelines with separate control locations.

Our leases have remaining lease terms of up to 32 years, some of which have options to extend the lease for up to an additional 27 years, and some of which may include options to terminate the lease within one year. Leasing activities and related leasing revenue and assets are not material to our consolidated financial statements.

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 common units 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 our Class P common shares.

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

Redeemable noncontrolling interest represents the interest in one of our consolidated subsidiaries, ELC, that is not owned by us, which in certain limited circumstances, the partner has the right to relinquish its interest in the subsidiary and redeem its cumulative contributions, net of distributions it has received through date of redemption. Net income (loss) attributable to redeemable noncontrolling interest was immaterial for the years ended December 31, 2019, 2018 and 2017 and is reported 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 income statements, the noncontrolling interest in the net income of our 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 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 for the amount that is, more likely than not, to 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.

Foreign Currency Transactions and Translation

The primary impact of foreign currency transactions and translation on us was with our Canadian assets that were included in the sale of KML and the TMPL Sale (see Note 3). Foreign currency transaction gains or losses result from a change in exchange rates between (i) the functional currency, for example the Canadian dollar for a Canadian subsidiary and (ii) the currency in which a foreign currency transaction is denominated, for example the U.S. dollar for a Canadian subsidiary. In our accompanying consolidated statements of income, gains and losses from our foreign currency transactions are included within "Other Income (Expense)—Other, net."

Foreign currency translation is the process of expressing, in U.S. dollars, amounts recorded in a local functional currency other than U.S. dollars, for example the Canadian dollar for a Canadian subsidiary. While we owned the Canadian assets, we translated the assets and liabilities of each of our consolidated foreign subsidiaries that have a local functional currency to U.S. dollars at year-end exchange rates. Income and expense items were translated at weighted-average rates of exchange prevailing during the year and stockholders' equity accounts were translated by using historical exchange rates. The cumulative translation adjustments balance was reported as a component of "Accumulated other comprehensive loss."

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 hedging the interest rate risk associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk with certain debt obligations, and prior to recent divestitures of our Canadian assets, our net investments in foreign operations. 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 entire change in fair value of the derivative is recorded as an adjustment to the item being hedged. The gain or loss from any mismatch in the hedging relationship is recognized currently in earnings. When we designate a derivative contract as a net investment accounting hedge, the entire change in fair value of the derivative is reflected in the Foreign currency translation adjustments section of Other comprehensive income on our consolidated statements of comprehensive income.

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 included 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, 2019 and 2018 (in millions):

	December 31,	
	2019	2018
Current regulatory assets	\$ 55	\$ 66
Non-current regulatory assets	212	245
Total regulatory assets(a)	\$ 267	\$ 311
Current regulatory liabilities	\$ 26	\$ 29
Non-current regulatory liabilities	189	206
Total regulatory liabilities(b)	\$ 215	\$ 235

- (a) Regulatory assets as of December 31, 2019 include (i) \$144 million of unamortized losses on disposal of assets; (ii) \$51 million income tax gross up on equity AFUDC; and (iii) \$72 million of other assets including amounts related to fuel tracker arrangements. Approximately \$84 million of the regulatory assets, with a weighted average remaining recovery period of 26 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, 2019 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 \$131 million of the \$189 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 18 years, while the remaining \$58 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 shares 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 shares and participating securities (in millions):

	Year Ended December 31,		
	2019	2018	2017
Net Income Available to Common Stockholders	\$ 2,190	\$ 1,481	\$ 27
Participating securities:			
Less: Net Income Allocated to Restricted stock awards(a)	(12)	(8)	(5)
Net Income Allocated to Class P Stockholders	\$ 2,178	\$ 1,473	\$ 22
Basic Weighted Average Common Shares Outstanding	2,264	2,216	2,230
Basic Earnings Per Common Share	\$ 0.96	\$ 0.66	\$ 0.01

(a) As of December 31, 2019, there were approximately 12 million such restricted stock awards.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share (in millions on a weighted average basis):

	Year Ended December 31,		
	2019	2018	2017
Unvested restricted stock awards	13	12	10
Warrants to purchase our Class P shares(a)	—	—	116
Convertible trust preferred securities	3	3	3
Mandatory convertible preferred stock(b)	—	48	58

(a) On May 25, 2017, approximately 293 million of unexercised warrants expired without the issuance of Class P common stock. Prior to expiration, each warrant entitled the holder to purchase one share of our common stock for an exercise price of \$40 per share. The potential dilutive effect of the warrants did not consider the assumed proceeds to KML upon exercise.

(b) The holder of each convertible preferred share participated in our earnings by receiving preferred stock dividends through the mandatory conversion date of October 26, 2018 at which time our convertible preferred shares were converted to common shares.

3. Divestitures

Sale of U.S. Portion of Cochin Pipeline and KML

On December 16, 2019, we closed on two cross-conditional transactions resulting in the sale of the U.S. portion of the Cochin Pipeline and all the outstanding equity of KML, including our 70% interest, to Pembina Pipeline Corporation (Pembina) (together, the "KML and U.S. Cochin Sale"). We recognized a pre-tax net gain of \$1,296 million from these transactions within "(Gain) loss on divestitures and impairments, net" on our accompanying consolidated statement of income during the year ended December 31, 2019. We received cash proceeds of \$1,553 million net of a working capital adjustment, for the U.S. portion of the Cochin Pipeline which was used to pay down debt. KML common shareholders received 0.3068 shares of Pembina common equity for each share of KML common equity. For our 70% interest in KML, we received approximately 25 million shares of Pembina common equity, with a pre-tax fair value on the transaction date of approximately \$892 million. The fair market value as of December 31, 2019 of the Pembina common shares was \$925 million and is reported as "Marketable securities at fair value" within our accompanying consolidated balance sheet as of December 31, 2019. Level 1 inputs in the fair value hierarchy were utilized to measure the fair value of the Pembina common shares. The Pembina common shares were subsequently sold on January 9, 2020, and we received proceeds of approximately \$907 million (\$764 million after tax).

Sale of Trans Mountain Pipeline System and Its Expansion Project

On August 31, 2018, KML completed the sale of the TMPL, the TMEP, the Puget Sound pipeline system for net cash consideration of C\$4.43 billion (U.S.\$3.4 billion), which is the contractual purchase price of C\$4.5 billion net of a preliminary working capital adjustment (the "TMPL Sale"). These assets comprised our Kinder Morgan Canada business segment. We

recognized a pre-tax gain from the TMPL Sale of \$595 million within "(Gain) loss on divestitures and impairments, net" in our accompanying consolidated statement of income during the year ended December 31, 2018. During the first quarter of 2019, KML settled the remaining C\$37 million (U.S.\$28 million) of working capital adjustments which amount was substantially accrued for as of December 31, 2018.

On January 3, 2019, KML distributed the net proceeds from the TMPL Sale to its shareholders as a return of capital. Public owners of KML's restricted voting shares, reflected as noncontrolling interests by us, received approximately \$0.9 billion (C\$1.2 billion), and most of our approximate 70% portion of the net proceeds of \$1.9 billion (C\$2.5 billion) (after Canadian tax) were used to repay our outstanding commercial paper borrowings of \$0.4 billion and in February 2019, to pay down approximately \$1.3 billion of maturing long-term debt.

May 2017 Sale of Approximate 30% Interest in Canadian Business

On May 30, 2017, KML completed an IPO of 102,942,000 restricted voting shares listed on the Toronto Stock Exchange at a price to the public of C\$17.00 per restricted voting share for total gross proceeds of approximately C\$1,750 million (U.S.\$1,299 million). The net proceeds from the IPO were used by KML to indirectly acquire from us an approximate 30% interest in a limited partnership that held our Canadian business while we retained the remaining 70% interest. We used the proceeds from KML's IPO to pay down debt. The portion of the Canadian business operations that we sold to the public on May 30, 2017 represented Canadian assets that were subsequently sold in the 2018 TMPL Sale and the 2019 KML and U.S. Cochin Sale.

Subsequent to the IPO, we retained control of KML and the limited partnership, and as a result, they remained consolidated in our consolidated financial statements until its sale in December 2019. For this period, our accompanying financial statements reflect the public ownership of the KML restricted voting shares as "Noncontrolling interests" and the earnings attributable to the public ownership of KML as "Net income attributable to noncontrolling interests."

As of and for the year ended December 31, 2017, as applicable, the KML IPO resulted in (i) "Contributions from noncontrolling interests - net proceeds from KML IPO" of \$1,245 million reported within our consolidated statement of cash flows; (ii) an adjustment to "Additional paid-in capital" of \$314 million reported within our consolidated statement of stockholders equity; and (iii) a net \$684 million increase to "Noncontrolling interests" reported within our consolidated statement of stockholders equity, including an allocation of currency translation adjustments from "Accumulated other comprehensive loss." The impact of the IPO also resulted in a deferred income tax adjustment of \$166 million.

Sale of Noncontrolling Interest in ELC

Effective February 28, 2017, we sold a 49% partnership interest in ELC to investment funds managed by EIG. We continue to own a 51% controlling interest in and operate ELC. Under the terms of ELC's limited liability company agreement, we are responsible for placing in service and operating certain supply pipelines and terminal facilities that support the operations of ELC and that are wholly owned by us. In certain limited circumstances that are not expected to occur, EIG has the right to relinquish its interest in ELC and redeem its capital account. The sale proceeds of \$386 million, and subsequent EIG contributions and distributions to EIG are presented in "Redeemable Noncontrolling Interest" on our consolidated balance sheets. Once these contingencies expire, EIG's capital account will be reflected in "Noncontrolling interests" on our consolidated balance sheets.

4. Gains and Losses on Divestitures and Impairments

During the years ended December 31, 2019, 2018, and 2017, we recorded net pre-tax gains of \$285 million and losses of \$437 million and \$172 million, respectively, reflecting net gains and losses on divestitures, impairments of certain equity investments, long-lived assets, and intangible assets. The year ended December 31, 2019 amount primarily includes a net pre-tax gain of \$1,296 million related to the KML and U.S. Cochin Sale (see Note 3) and impairment losses of \$1,014 million as further described below.

The impairments were driven by market conditions that existed at the time and required management to estimate the fair value of the assets. The estimates of fair value are based on Level 3 valuation estimates using industry standard income approach valuation methodologies which include assumptions primarily involving management's significant judgments and estimates with respect to general economic conditions and the related demand for products handled or transported by our assets as well as assumptions regarding commodity prices, future cash flows based on rate and volume assumptions, terminal values and discount rates. We typically use discounted cash flow analyses to determine the fair value of our assets. We may probability weight various forecasted cash flow scenarios utilized in the analysis as we consider the possible outcomes. We use

discount rates representing our estimate of the risk-adjusted discount rates that would be used by market participants specific to the particular asset.

We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill that could result in future 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 be not fully recoverable.

We recognized the following non-cash pre-tax (gains) losses on divestitures of and impairment charges on assets (in millions):

	Year Ended December 31,		
	2019	2018	2017
Natural Gas Pipelines			
Impairments of long-lived assets(a)	\$ 290	\$ 636	\$ 30
Gains on divestitures of long-lived assets(b)	(967)	(6)	—
Impairments of equity investments(c)	650	270	150
Impairment at equity investee(d)	—	—	10
Terminals			
Impairments of long-lived assets(e)	—	59	3
Gains on divestitures of long-lived assets(f)	(335)	(6)	(18)
CO₂			
Impairments of long-lived assets(g)	74	79	(1)
Losses on divestitures of long-lived assets	2	—	—
Impairment at equity investee	—	—	(4)
Kinder Morgan Canada			
Losses (gain) on divestiture of long-lived assets(h)	2	(595)	—
Other (gains) losses on divestitures of long-lived assets	(1)	—	2
Pre-tax (gains) losses on divestitures and impairments, net	\$ (285)	\$ 437	\$ 172

(a) 2019 amount represents the non-cash impairments associated with certain gathering and processing assets in Oklahoma and northern Texas. 2018 amount represents the non-cash impairment associated with certain gathering and processing assets in Oklahoma and a project write-off associated with the Utica Marcellus Texas pipeline. 2017 amount represents the impairment of our Colden storage facility, of which \$3 million is included in "Costs of sales" on our accompanying consolidated statement of income.

(b) 2019 amount includes a \$957 million gain related to the KML and U.S. Cochin Sale.

(c) Non-cash impairments of equity investments are included in "Earnings from equity investments" on our accompanying consolidated statements of income for the years ended December 31, 2019, 2018 and 2017. 2019 amount represents the non-cash impairment of our investment in Ruby. 2018 amount represents the non-cash impairment of our investment in Gulf LNG Holdings Group, LLC (Gulf LNG) which was driven by a ruling by an arbitration panel affecting a customer contract. Our share of earnings recognized by Gulf LNG on the respective customer contract is included in "Earnings from equity investments" on our accompanying consolidated statement of income for the year ended December 31, 2018. 2017 amount represents the non-cash impairment of our investment in FEP.

(d) 2017 amount represents losses on impairments recorded by equity investees and are included in "Earnings from equity investments" on our accompanying consolidated statement of income.

(e) 2018 amount primarily relates to non-cash impairments of certain northeast terminal assets.

(f) 2019 amount includes a \$339 million gain related to the sale of KML and a \$7 million loss included in "Other, net" on our accompanying consolidated statement of income, related to a sale of an equity investment. 2017 amount includes a \$23 million gain related to the sale of a 40% membership interest in the Deeprack Development joint venture.

(g) 2019 and 2018 amounts represent impairments of oil and gas properties.

(h) 2019 and 2018 amounts represent a working capital adjustment and gain on sale, respectively, associated with the TMPL Sale.

Our largest impairment for the year ended December 31, 2019 was a \$650 million non-cash impairment to our investment in Ruby in our Natural Gas Pipelines business segment. The impairment of our investment was considered from our subordinated ownership position and driven by reduced cash flow estimates identified during the period which resulted from (i) increased Canadian gas supplies and competition from other natural gas pipelines and (ii) upcoming contract expirations. These conditions were determined to be other than temporary. We utilized a discounted cash flow analysis.

Additional impairments totaling \$290 million were recognized during the year ended December 31, 2019 on long-lived assets within our Natural Gas Pipelines business segment and were driven by continued reduced drilling activity in Oklahoma and northern Texas demonstrated in the fourth quarter. Our largest impairment for the year ended December 31, 2018 was a \$600 million non-cash impairment in our Natural Gas Pipelines business segment driven by reduced cash flow estimates for some of our gathering and processing assets in Oklahoma identified during the period as a result of our decision to redirect our focus to other areas of our portfolio.

For our long-lived assets, the reduced estimates triggered an impairment analysis, in each case, as we determined that our carrying value may no longer be recoverable. The impairment analysis for long-lived assets was based upon a two-step process as prescribed in the accounting standards. Step 1 involved comparing the undiscounted future cash flows to be derived from the asset group to the carrying value of the asset group. Based on the results of our step 1 test, we determined that the undiscounted future cash flows were less than the carrying value of the asset group. Step 2 involved using the income approach to calculate the fair value of the asset group and comparing it to the carrying value. The impairment that we recorded represented the difference between the fair and carrying values.

5. Income Taxes

The components of "Income Before Income Taxes" are as follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
U.S.	\$ 2,482	\$ 1,739	\$ 1,976
Foreign	683	767	185
Total Income Before Income Taxes	\$ 3,165	\$ 2,506	\$ 2,161

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

	Year Ended December 31,		
	2019	2018	2017
Current tax expense (benefit)			
Federal	\$ (2)	\$ (22)	\$ (137)
State	10	(45)	(16)
Foreign(a)	201	249	18
Total	209	182	(135)
Deferred tax expense (benefit)			
Federal	682	425	2,022
State	66	55	4
Foreign(a)	(31)	(75)	47
Total	717	405	2,073
Total tax provision	\$ 926	\$ 587	\$ 1,938

(a) Our Canada income tax expense was \$165 million, \$168 million and \$58 million for the years ended December 31, 2019, 2018 and 2017, respectively.

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows (in millions, except percentages):

	Year Ended December 31,					
	2019		2018		2017	
Federal income tax	\$ 665	21.0 %	\$ 526	21.0 %	\$ 756	35.0 %
Increase (decrease) as a result of:						
Taxes on foreign earnings, net of federal benefit	139	4.4 %	131	5.2 %	42	1.9 %
Net effects of noncontrolling interests	(10)	(0.3)%	(65)	(2.6)%	(14)	(0.7)%
State income tax, net of federal benefit	68	2.1 %	46	1.8 %	38	1.8 %
Dividend received deduction	(39)	(1.1)%	(31)	(1.2)%	(56)	(2.6)%
Adjustments to uncertain tax positions	(5)	(0.2)%	(47)	(1.9)%	(12)	(0.6)%
Impact of the 2017 Tax Reform	—	— %	—	— %	1,240	57.4 %
Nondeductible goodwill	108	3.4 %	58	2.3 %	—	— %
General business credit	—	— %	(64)	(2.6)%	(95)	(4.4)%
Other	—	— %	33	1.4 %	39	1.9 %
Total	\$ 926	29.3 %	\$ 587	23.4 %	\$ 1,938	89.7 %

Deferred tax assets and liabilities result from the following (in millions):

	December 31,	
	2019	2018
Deferred tax assets		
Employee benefits	\$ 208	\$ 238
Accrued expenses	86	76
Net operating loss, capital loss and tax credit carryforwards	1,519	1,526
Derivative instruments and interest rate and currency swaps	15	9
Debt fair value adjustment	29	33
Investments	—	177
Valuation allowances	(155)	(178)
Total deferred tax assets	1,702	1,881
Deferred tax liabilities		
Property, plant and equipment	385	270
Investments	418	—
Other	42	45
Total deferred tax liabilities	845	315
Net deferred tax assets	\$ 857	\$ 1,566

Deferred Tax Assets and Valuation Allowances

We have deferred tax assets of \$1,261 million related to net operating loss carryovers, \$258 million related to general business and foreign tax credits, and \$117 million of valuation allowances related to these deferred tax assets as of December 31, 2019. As of December 31, 2018, we had deferred tax assets of \$1,249 million related to net operating loss carryovers, \$260 million related to general business, alternative minimum and foreign tax credits, \$17 million related to capital losses and \$140 million of valuation allowances related to these deferred tax assets. We expect to generate taxable income and begin to utilize federal net operating loss carryforwards and tax credits in 2023.

We decreased our valuation allowances in 2019 by \$23 million, primarily due to the \$18 million utilization of the capital loss carryover from the capital gain generated by the KML and U.S. Cochin Sale.

Expiration Periods for Deferred Tax Assets: As of December 31, 2019, we have U.S. federal net operating loss carryforwards of \$1.5 billion that will be carried forward indefinitely and \$3.4 billion that will expire from 2020 - 2037; state losses of \$3.3 billion which will expire from 2020 - 2038; and foreign losses of \$107 million which will expire from 2029 - 2038. We also have \$241 million of general business credits which will expire from 2020 - 2038; and approximately \$17 million of foreign tax credits, which will expire from 2020 - 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.

The merger transactions that occurred in November 2014 resulted in a deferred tax asset, primarily related to our investment in KMP, the balance of which was approximately \$583 million as of December 31, 2018. As earnings from our investment in KMP exceeded taxable income (primarily as a result of the partnership's tax depreciation in excess of book depreciation), this reduced the deferred tax asset related to our investment in KMP so that it now represents a deferred tax liability of \$48 million as of December 31, 2019.

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.

Our gross unrecognized tax benefit balances, excluding immaterial amounts of interest and penalties, were \$16 million, \$34 million and \$97 million as of December 31, 2019, 2018 and 2017, respectively. Reductions based on settlements with taxing authorities were \$21 million, \$73 million and \$22 million for the years ended December 31, 2019, 2018 and 2017, respectively. All of the \$16 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will increase by approximately \$3 million during the next year to approximately \$19 million, primarily due to additions for state filing positions taken in prior years.

We are subject to taxation, and have tax years open to examination for the periods 2015-2018 in the U.S., 2005-2018 in various states and 2007-2018 in various foreign jurisdictions.

Impact of 2017 Tax Reform

During the year ended December 31, 2017 we recorded a provisional non-cash adjustment of \$1,240 million resulting from the enactment of the 2017 Tax Reform which caused us to re-measure our deferred tax assets related to our net operating loss carryforwards and tax credits, in addition to tax basis in excess of accounting basis primarily related to our investment in KMP at the new income tax rate of 21% from the previous income tax rate of 35%. Additionally, during the year ended December 31, 2017, we recorded a provisional non-cash adjustment of approximately \$144 million after-tax (\$219 million pre-tax), including our share of equity investee provisional adjustments, related to our FERC regulated business. During the year ended December 31, 2018, we decreased this non-cash provisional adjustment by approximately \$27 million after-tax (\$36 million pre-tax).

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2019 and 2018, our property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2019	2018
Pipelines (Natural gas, liquids, crude oil and CO ₂)	\$ 19,856	\$ 19,727
Equipment (Natural gas, liquids, crude oil, CO ₂ , and terminals)	25,791	24,392
Other(a)	5,360	5,447
Accumulated depreciation, depletion and amortization	(16,950)	(15,359)
	34,057	34,207
Land and land rights-of-way	1,356	1,378
Construction work in process	1,006	2,312
Property, plant and equipment, net	\$ 36,419	\$ 37,897

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

As of December 31, 2019 and 2018, property, plant and equipment, net included \$12,229 million and \$12,349 million, respectively, of assets which were regulated by either the FERC or, prior to the sales of TMPL and KML, by the NEB. Depreciation, depletion, and amortization expense charged against property, plant and equipment was \$2,176 million, \$2,057 million, and \$2,022 million for the years ended December 31, 2019, 2018, and 2017, respectively.

Asset Retirement Obligations

As of December 31, 2019 and 2018, we recognized asset retirement obligations in the aggregate amount of \$218 million and \$213 million, respectively, of which \$4 million were classified as current for both periods. The majority of our asset retirement obligations are associated with our CO₂ business segment, 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.

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, 2019 and 2018, and our earnings (losses) from these respective investments for the years ended December 31, 2019, 2018 and 2017 (in millions):

	Ownership Interest	Equity Investments		Earnings (Losses) from Equity Investments			
		December 31,		Year ended December 31,			
		2019	2018	2019	2018	2017	
Citrus Corporation	50%	\$ 1,856	\$ 1,708	\$ 157	\$ 169	\$ 108	
SNG	50%	1,473	1,536	140	141	77	
NGPL Holdings LLC(a)	50%	721	733	81	66	10	
Gulf Coast Express Pipeline LLC	34%	656	240	37	2	—	
MEP	50%	439	235	15	31	38	
Gulf LNG(b)	50%	361	361	17	(61)	47	
Plantation Pipe Line Company	51%	348	344	58	55	46	
Utopia Holding LLC	50%	335	333	20	14	—	
Permian Highway Pipeline	27%	309	45	—	—	—	
EagleHawk	25%	285	299	17	7	24	
Watco Companies, LLC	(c)	185	185	19	21	19	
FEP(d)	50%	102	44	59	55	(97)	
Ruby(e)	(f)	41	750	(609)	26	44	
Cortez Pipeline Company	53%	26	15	35	36	44	
All others			622	653	55	55	68
Total investments		\$ 7,759	\$ 7,481	\$ 101	\$ 617	\$ 428	
Amortization of excess cost				\$ (83)	\$ (95)	\$ (61)	

- (a) Investment in NGPL Holdings LLC (NGPL) includes a related party promissory note receivable with a principal amount of \$500 million as of December 31, 2019. On October 1, 2019, NGPL issued a non-cash related party promissory note with a principal amount of \$500 million as a capital distribution. The related party promissory note accrues interest at 6.75% and is payable quarterly. From the issuance of the related party promissory note receivable through December 31, 2019, we recognized \$8.4 million of interest within "Earnings from equity investments" on our accompanying consolidated statement of income.
- (b) The loss from Gulf LNG for the year ended December 31, 2018 includes our share of earnings recognized due to a ruling by an arbitration panel affecting a customer contract. 2018 amount also includes a non-cash impairment charge of \$270 million (pre-tax) driven by this ruling. See Note 4 for more information.
- (c) We hold a preferred and common equity investment in Watco Companies, LLC. We own 100,000 Class A and 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 3.25% and 3.00% per quarter, respectively. Neither class holds any voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. In addition to the senior interests, we also hold approximately 13,000 common equity units, which represents a 3.0% common ownership.
- (d) The loss from FEP for the year ended December 31, 2017 amount includes a non-cash impairment charges of \$150 million (pre-tax) related to our investment. See Note 4 for more information.
- (e) The loss from Ruby for the year ended December 31, 2019 amount includes a non-cash impairment charges of \$650 million (pre-tax) related to our investment. See Note 4 for more information.
- (f) We operate Ruby and own the common interest in Ruby, the sole owner of the Ruby Pipeline natural gas transmission system. Pembina Pipeline Corporation (Pembina) owns the remaining interest in Ruby in the form of a convertible preferred interest. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby.

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

Income Statement	Year Ended December 31,		
	2019	2018	2017
Revenues	\$ 4,906	\$ 4,898	\$ 4,406
Costs and expenses	3,508	3,245	3,219
Net income	\$ 1,398	\$ 1,653	\$ 1,187

Balance Sheet	December 31,	
	2019	2018
Current assets	\$ 1,195	\$ 1,422
Non-current assets	24,743	22,615
Current liabilities	2,125	2,683
Non-current liabilities	9,670	9,484
Partners'/owners' equity	14,143	11,870

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2019 and 2018 are summarized by reporting unit as follows (in millions):

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non- Regulated	CO ₂	Products Pipelines	Products Pipelines Terminals	Terminals	Kinder Morgan Canada	Total
Gross goodwill	\$ 15,892	\$ 5,812	\$ 1,528	\$ 2,125	\$ 221	\$ 1,572	\$ 575	\$ 27,725
Accumulated impairment losses	(1,643)	(1,597)	—	(1,197)	(70)	(679)	(377)	(5,563)
December 31, 2017	14,249	4,215	1,528	928	151	893	198	22,162
Currency translation	—	—	—	—	—	—	(8)	(8)
Divestitures(a)	—	—	—	—	—	—	(190)	(190)
Other	—	—	—	—	—	1	—	1
December 31, 2018	14,249	4,215	1,528	928	151	894	—	21,965
Divestitures(b)	—	(422)	—	—	—	(92)	—	(514)
Transfer(c)	—	(450)	—	450	—	—	—	—
Gross goodwill	15,892	4,940	1,528	2,575	221	1,481	—	26,637
Accumulated impairment losses	(1,643)	(1,597)	—	(1,197)	(70)	(679)	—	(5,186)
December 31, 2019	\$ 14,249	\$ 3,343	\$ 1,528	\$ 1,378	\$ 151	\$ 802	\$ —	\$ 21,451

(a) 2018 includes \$190 million related to the TMPL Sale, including all of the accumulated impairment losses for our Kinder Morgan Canada reporting unit. See Note 3 for more information.

(b) 2019 includes \$514 million related to the KML and U.S. Cochin Sale. See Note 3 for more information.

(c) Effective January 1, 2019, for segment reporting purposes, certain assets were transferred among our business segments which resulted in the transfer of goodwill from the Natural Gas Pipelines Non-Regulated reporting unit to the Products Pipelines reporting unit. See Note 16 for more information.

Refer to Note 2 "Summary of Significant Accounting Policies—Goodwill" for a description of our accounting for goodwill.

As of May 31, 2019, the results of our annual Step 1 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%) and as such, step 2 was not required. We did not identify any triggers requiring further impairment analysis during the remainder of the year.

We estimated fair value based primarily 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 representing the price estimated to be received in a sale of the reporting unit in an orderly transaction between market participants at the measurement date. For our Natural Gas Pipelines Non-Regulated reporting unit, our May 31, 2019 annual test also considered a discounted cash flow analysis (income approach) to evaluate the fair value of this reporting unit to provide an additional indication of fair value based on the present value of cash flows this reporting unit is expected to generate in the future. We weighted the market and income approaches to arrive at an estimated fair value of this reporting unit as we believed the income approach reflects the value a market participant would place on our growth projects that are not fully reflected under a market approach, which considers only near term forecasted EBITDA projections. However, as both approaches yielded a fair value estimate that exceeded the reporting unit's carrying value, we do not consider the income approach or the relative weighting of these approaches to be significant assumptions in reaching our conclusion that goodwill is not impaired.

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 (in millions):

	December 31,	
	2019	2018
Credit facility and commercial paper borrowings(a)	\$ 37	\$ 433
Corporate senior notes(b)		
9.00%, due February 2019	—	500
2.65%, due February 2019	—	800
3.05%, due December 2019	—	1,500
6.85%, due February 2020	700	700
6.50%, due April 2020	535	535
5.30%, due September 2020	600	600
6.50%, due September 2020	349	349
5.00%, due February 2021	750	750
3.50%, due March 2021	750	750
5.80%, due March 2021	400	400
5.00%, due October 2021	500	500
4.15%, due March 2022	375	375
1.50%, due March 2022(c)	841	860
3.95%, due September 2022	1,000	1,000
3.15%, due January 2023	1,000	1,000
Floating rate, due January 2023(d)	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
6.70%, due February 2027	7	7
2.25%, due March 2027(c)	561	573
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

(continued)	December 31,	
	2019	2018
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
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
7.45%, due March 2098	26	26
TGP senior notes(b)		
7.00%, due March 2027	300	300
7.00%, due October 2028	400	400
8.375%, due June 2032	240	240
7.625%, due April 2037	300	300
EPNG senior notes(b)		
8.625%, due January 2022	260	260
7.50%, due November 2026	200	200
8.375%, due June 2032	300	300
CIG senior notes(b)		
4.15%, due August 2026	375	375
6.85%, due June 2037	100	100
EPC Building, LLC, promissory note, 3.967%, due January 2020 through December 2035	395	409
Trust I Preferred Securities, 4.75%, due March 2028(e)	221	221
KMGP, \$1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(f)	100	100
Other miscellaneous debt(g)	258	250
Total debt – KMI and Subsidiaries	33,360	36,593
Less: Current portion of debt(h)	2,477	3,388
Total long-term debt – KMI and Subsidiaries(i)	\$ 30,883	\$ 33,205

(a) See “—Current portion of debt” below for further details regarding the outstanding credit facility and commercial paper borrowings.

(b) 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.

(c) Consists of senior notes denominated in Euros that have been converted to U.S. dollars and are respectively reported above at the December 31, 2019 exchange rate of 1.1213 U.S. dollars per Euro and at the December 31, 2018 exchange rate of 1.1467 U.S. dollars per Euro. As of December 31, 2019 and 2018, the cumulative changes in the exchange rate of U.S. dollars per Euro since issuance had resulted in increases to our debt balance of \$26 million and \$46 million, respectively, related to the 1.50% series and increases of \$18 million and \$30 million, respectively, related to the 2.25% series. The cumulative increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in “Deferred charges and other assets” and “Other long-term liabilities and deferred credits” on our consolidated balance sheets. At the time of issuance, we entered into foreign currency contracts associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 14 “Risk Management—Foreign Currency Risk Management”).

- (d) During the year ended December 31, 2019, we entered into a floating-to-fixed interest rate swap agreement which was designated as a cash flow hedge.
- (e) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2019, 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, 2019 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.
- (f) As of December 31, 2019 and 2018, KMGP had outstanding 100,000 shares of its \$1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057, which was redeemed including accrued dividends on January 15, 2020.
- (g) Includes capital lease obligations with monthly installments. The lease terms expire between 2024 and 2061.
- (h) Amounts include KMI outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months. See "—Current Portion of Debt" below.
- (i) Excludes our "Debt fair value adjustments" which, as of December 31, 2019 and 2018, increased our combined debt balances by \$1,032 million and \$731 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.

Current Portion of Debt

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

	December 31,	
	2019	2018
\$500 million, 364-day credit facility due November 15, 2019	\$ —	\$ —
\$4 billion credit facility due November 16, 2023	—	—
Commercial paper notes(a)	37	433
Current portion of senior notes		
9.00%, due February 2019	—	500
2.65%, due February 2019	—	800
3.05%, due December 2019	—	1,500
6.85%, due February 2020	700	—
6.50%, due April 2020	535	—
5.30%, due September 2020	600	—
6.50%, due September 2020	349	—
Trust I Preferred Securities, 4.75%, due March 2028(b)	111	111
KMGP, \$1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(c)	100	—
Current portion of other debt	45	44
Total current portion of debt	\$ 2,477	\$ 3,388

- (a) Weighted average interest rates on borrowings outstanding as of December 31, 2019 and 2018 were 1.90% and 3.10%, respectively.
- (b) 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.
- (c) In December 2019, we notified the holder of our intent to redeem these securities. As our notification was irrevocable, the outstanding balance was classified as current in our accompanying balance sheet as of December 31, 2019. We redeemed these securities including accrued dividends on January 15, 2020.

We and substantially all of our wholly owned domestic subsidiaries are a 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. Also, see Note 20.

Credit Facility and Restrictive Covenants

As of December 31, 2019, we had borrowing capacity of approximately \$3.9 billion under our \$4 billion revolving credit facility. We also continue to maintain a \$4 billion commercial paper program through the private placement of short-term notes. 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 revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. Our additional \$500 million, 364-day credit facility expired on November 15, 2019.

Depending on the type of loan request, our credit facility borrowings under our credit facility bear interest at either (i) LIBOR adjusted for a eurocurrency funding reserve plus an applicable margin ranging from 1.000% to 2.000% 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) LIBOR for a one-month eurodollar loan adjusted for a eurocurrency funding reserve, plus 1%, plus, in each case, an applicable margin ranging from 0.100% to 1.000% 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 0.300%.

Our credit facility contains 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 facility) 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 facility also restricts our ability to make certain restricted payments if an event of default (as defined in the credit facility) has occurred and is continuing or would occur and be continuing.

As of December 31, 2019, we had no borrowings outstanding under our credit facility, \$37 million outstanding under our commercial paper program and \$84 million in letters of credit. Our availability under this facility as of December 31, 2019 was approximately \$3.9 billion. As of December 31, 2019, 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, 2019, are summarized as follows (in millions):

Year	Total
2020(a)	\$ 2,477
2021	2,422
2022	2,500
2023	3,250
2024	1,925
Thereafter	20,786
Total	\$ 33,360

(a) Includes long-term debt securities with maturity dates beyond a year that have met certain criteria to be classified in whole or in part as current.

Debt Fair Value Adjustments

The following table summarizes the “Debt fair value adjustments” included on our accompanying consolidated balance sheets (in millions):

Debt Fair Value Adjustments	December 31,	
	2019	2018
Purchase accounting debt fair value adjustments	\$ 599	\$ 658
Carrying value adjustment to hedged debt	359	2
Unamortized portion of proceeds received from the early termination of interest rate swap agreements(a)	257	275
Unamortized debt discounts, net	(67)	(74)
Unamortized debt issuance costs	(116)	(130)
Total debt fair value adjustments	\$ 1,032	\$ 731

(a) As of December 31, 2019, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 15 years.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances is disclosed below (in millions):

	December 31, 2019		December 31, 2018	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	\$ 34,392	\$ 38,016	\$ 37,324	\$ 37,469

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2019 and 2018.

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 5.27% during 2019 and 5.15% during 2018. 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 Shares

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

We have a Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. 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 to receive shares of Class P common stock. Each election will be generally at or around the first board of directors meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2019, 2018 and 2017, we made restricted Class P common stock grants to our non-employee directors of 23,100, 25,800 and 17,740, respectively. These grants were valued at time of issuance at \$400,000, \$500,000 and \$400,000, respectively. All of the restricted stock awards made to non-employee directors vest during a six-month period.

Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan

The Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan is an equity awards plan available to eligible employees. The total number of shares of Class P common stock authorized under the plan is 33,000,000. The following table sets forth a summary of activity and related balances of our restricted stock awards excluding that issued to non-employee directors (in millions, except share and per share amounts):

	Year Ended December 31, 2019		Year Ended December 31, 2018		Year Ended December 31, 2017	
	Shares	Weighted Average Grant Date Fair Value per Share	Shares	Weighted Average Grant Date Fair Value per Share	Shares	Weighted Average Grant Date Fair Value per Share
Outstanding at beginning of period	13,154,605	\$ 22.59	10,518,344	\$ 28.21	9,038,137	\$ 32.72
Granted	3,791,674	20.46	5,389,476	17.73	3,221,691	19.52
Vested	(4,259,169)	28.15	(2,371,193)	36.34	(1,501,939)	36.67
Forfeited	(273,554)	21.22	(382,022)	23.26	(239,545)	28.34
Outstanding at end of period	12,413,556	20.07	13,154,605	22.59	10,518,344	28.21

The intrinsic value of restricted stock awards vested during the years ended December 31, 2019, 2018 and 2017 was \$87 million, \$42 million and \$30 million, respectively. Restricted stock awards made to employees have vesting periods ranging from 1 year up to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares
2020	3,271,081
2021	4,628,872
2022	3,356,768
2023	549,164
2024	127,173
Thereafter	480,498
Total Outstanding	12,413,556

During 2019, 2018 and 2017, we recorded \$62 million, \$63 million and \$65 million, respectively, in expense related to restricted stock awards and capitalized approximately \$12 million, \$13 million and \$9 million, respectively. At December 31, 2019, unrecognized restricted stock awards compensation costs, less estimated forfeitures, was approximately \$119 million with a weighted average remaining amortization period of 2.23 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 \$50 million, \$48 million, and \$47 million for the years ended December 31, 2019, 2018 and 2017, 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.

Additionally, our subsidiary SFPP has incurred certain liabilities for postretirement benefits to certain current and former employees, their covered dependents, and their beneficiaries. However, the net periodic benefit costs, contributions and liability amounts associated with the SFPP postretirement benefit plan are not material to our consolidated income statements or balance sheets.

Plans Associated with Foreign Operations

Two of our former subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline ULC (as general partner of Trans Mountain Pipeline L.P.), were sponsors of pension and OPEB plans for eligible Canadian and Trans Mountain pipeline employees. These subsidiaries, along with the plan assets of the Canadian pension and OPEB plans, were sold on August 31, 2018 (see Note 3). In conjunction with the TMPL Sale, Kinder Morgan Canada Services was formed and became the Canadian employer of the staff that operated our remaining Canadian assets. Kinder Morgan Canada Services subsequently established a defined contribution pension plan and an OPEB plan for eligible Canadian employees which are not material to our consolidated income statements and balance sheets, and therefore are excluded from the following disclosures. Kinder Morgan Canada Services and the related benefit plans were subsequently disposed of as part of the KML and U.S. Cochin Sale (see Note 3).

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, 2019 and 2018 (in millions):

	Pension Benefits		OPEB	
	2019	2018	2019	2018
Change in benefit obligation:				
Benefit obligation at beginning of period	\$ 2,566	\$ 2,982	\$ 339	\$ 425
Service cost	53	52	1	1
Interest cost	96	84	12	12
Actuarial loss (gain)	159	(172)	10	(53)
Benefits paid	(178)	(175)	(32)	(33)
Participant contributions	—	—	2	1
Medicare Part D subsidy receipts	—	—	1	1
Other(a)	—	(205)	—	(15)
Benefit obligation at end of period	2,696	2,566	333	339
Change in plan assets:				
Fair value of plan assets at beginning of period	1,864	2,296	306	335
Actual return on plan assets	330	(128)	49	(5)
Employer contributions	60	30	7	7
Participant contributions	—	—	2	1
Medicare Part D subsidy receipts	—	—	1	1
Benefits paid	(178)	(175)	(32)	(33)
Other(a)	—	(159)	—	—
Fair value of plan assets at end of period	2,076	1,864	333	306
Funded status - net liability at December 31,	\$ (620)	\$ (702)	\$ —	\$ (33)

(a) 2018 amounts represent December 31, 2017 balances associated with Canadian pension and OPEB plans that were included in the TMPL Sale.

Components of Funded Status. The following table details the amounts recognized in our balance sheets at December 31, 2019 and 2018 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2019	2018	2019	2018
Non-current benefit asset(a)	\$ —	\$ —	\$ 231	\$ 190
Current benefit liability	—	—	(18)	(13)
Non-current benefit liability	(620)	(702)	(213)	(210)
Funded status - net liability at December 31,	\$ (620)	\$ (702)	\$ —	\$ (33)

(a) 2019 and 2018 OPEB amounts include \$39 million and \$32 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.

Components of Accumulated Other Comprehensive (Loss) Income. The following table details the amounts of pre-tax accumulated other comprehensive (loss) income at December 31, 2019 and 2018 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets (in millions):

	Pension Benefits		OPEB	
	2019	2018	2019	2018
Unrecognized net actuarial (loss) gain	\$ (557)	\$ (653)	\$ 123	\$ 117
Unrecognized prior service (cost) credit	(3)	(3)	12	14
Accumulated other comprehensive (loss) income	\$ (560)	\$ (656)	\$ 135	\$ 131

We anticipate that approximately \$25 million of pre-tax accumulated other comprehensive loss, inclusive of amounts reported as noncontrolling interests, will be recognized as part of our net periodic benefit cost in 2020, including approximately \$27 million of unrecognized net actuarial loss and approximately \$2 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was \$2,659 million and \$2,535 million at December 31, 2019 and 2018, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was \$288 million and \$293 million at December 31, 2019 and 2018, respectively. The fair value of these plans' assets was approximately \$57 million and \$70 million at December 31, 2019 and 2018, respectively.

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.

As of December 31, 2019, the allowable range for asset allocations in effect for our pension plan were 34% to 59% equity, 37% to 57% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock and/or debt securities). As of December 31, 2019, the allowable range for asset allocations in effect for our OPEB plans were 45% to 68% equity, 25% to 50% fixed income and 0% to 22% cash.

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.
- Level 3 assets' fair values are calculated using valuation techniques that require inputs that are both significant to the fair value measurement and are unobservable, or are similar to Level 2 assets. Included in this level are guaranteed insurance contracts which are valued at contract value, which approximates fair value.
- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), 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, 2019 and 2018 (in millions):

	Pension Assets							
	2019				2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Short-term investment funds	\$ —	\$ 50	\$ —	\$ 50	\$ —	\$ 7	\$ —	\$ 7
Mutual funds(a)	—	—	—	—	81	—	—	81
Equities(b)	296	—	—	296	227	—	—	227
Fixed income securities(c)	—	405	—	405	—	422	—	422
Derivatives	—	12	—	12	—	6	—	6
Subtotal	\$ 296	\$ 467	\$ —	763	\$ 308	\$ 435	\$ —	743
Measured at NAV(d)								
Common/collective trusts(e)				1,069				857
Private investment funds(f)				200				215
Private limited partnerships(g)				44				49
Subtotal				1,313				1,121
Total plan assets fair value				\$ 2,076				\$ 1,864

(a) Includes mutual funds which are invested in equity.

(b) Plan assets include \$129 million and \$94 million of KMI Class P common stock for 2019 and 2018, respectively.

(c) Plan assets include \$1 million of KMI debt securities for 2019.

(d) Plan assets which used NAV as a practical expedient to measure fair value.

(e) Common/collective trust funds were invested in approximately 32% fixed income and 68% equity in 2019 and 37% fixed income and 63% equity in 2018.

(f) Private investment funds were invested in approximately 73% fixed income and 27% equity in 2019 and 71% fixed income and 29% equity in 2018.

(g) Includes assets invested in real estate, venture and buyout funds.

	OPEB Assets							
	2019				2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash	\$ 1	\$ —	\$ —	\$ 1	\$ —	\$ —	\$ —	\$ —
Short-term investment funds	—	5	—	5	—	4	—	4
Equities	25	—	—	25	—	—	—	—
Fixed income securities	—	17	—	17	—	—	—	—
Guaranteed insurance contracts	—	—	—	—	—	—	51	51
Mutual funds(a)	11	—	—	11	1	—	—	1
Subtotal	\$ 37	\$ 22	\$ —	59	\$ 1	\$ 4	\$ 51	56
Measured at NAV(b)								
Common/collective trusts(c)				274				250
Subtotal				274				250
Total plan assets fair value				\$ 333				\$ 306

(a) Includes mutual funds which are invested in equities and fixed income securities.

(b) Plan assets which used NAV as a practical expedient to measure fair value.

(c) Common/collective trust funds were invested in approximately 64% equity and 36% fixed income securities for 2019 and 60% equity and 40% fixed income securities for 2018.

The following table presents the changes in our OPEB plans' assets included in Level 3 for the years ended December 31, 2019 and 2018 (in millions):

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)(a)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2019					
Guaranteed insurance contracts	\$ 51	\$ (49)	\$ —	\$ (2)	\$ —
2018					
Guaranteed insurance contracts	\$ 49	\$ —	\$ 4	\$ (2)	\$ 51

(a) Guaranteed insurance contracts were canceled and the individual securities within the contracts were transferred in-kind to Level 1 or Level 2.

Changes in the underlying value of Level 3 assets due to the effect of changes of fair value were immaterial for the years ended December 31, 2019 and 2018.

Expected Payment of Future Benefits and Employer Contributions . As of December 31, 2019, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2020	\$ 239	\$ 32
2021	230	31
2022	229	30
2023	218	29
2024	212	27
2025 - 2029	939	115

(a) Includes a reduction of approximately \$1 million in each of the years 2020 through 2024 and approximately \$6 million in aggregate for the period 2025 - 2029 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In 2020, we expect to contribute approximately \$71 million to our pension plans and \$7 million, net of anticipated subsidies, to our OPEB plans.

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 and net benefit costs of our pension and OPEB plans for 2019, 2018 and 2017:

	Pension Benefits			OPEB		
	2019	2018	2017	2019	2018	2017
Assumptions related to benefit obligations:						
Discount rate	3.17%	4.26%	3.56%	3.03%	4.16%	3.48%
Rate of compensation increase	3.50%	3.50%	3.53%	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate for benefit obligations	4.26%	3.56%	3.83%	4.16%	3.48%	3.69%
Discount rate for interest on benefit obligations	3.89%	3.13%	3.09%	3.83%	3.08%	3.05%
Discount rate for service cost	4.28%	3.56%	3.88%	4.51%	3.82%	4.15%
Discount rate for interest on service cost	3.93%	3.14%	3.24%	4.46%	3.76%	3.95%
Expected return on plan assets(a)	7.25%	7.25%	7.07%	6.50%	7.08%	6.84%
Rate of compensation increase	3.50%	3.50%	3.52%	n/a	n/a	n/a

(a) 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 (UBIT), we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on a UBIT rate of 27% for 2019 and 21% for 2018 and 2017.

We utilize a full yield curve approach in the estimation of 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.

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 8.38% which gradually decreases to 4.54% by the year 2038. Assumed health care cost trends could have a significant effect on the amounts reported for the OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2019 and 2018 (in millions):

	2019	2018
One-percentage point increase:		
Aggregate of service cost and interest cost	\$ 1	\$ 1
Accumulated postretirement benefit obligation	14	16
One-percentage point decrease:		
Aggregate of service cost and interest cost	\$ —	\$ (1)
Accumulated postretirement benefit obligation	(12)	(14)

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 (in millions):

	Pension Benefits			OPEB		
	2019	2018	2017	2019	2018	2017
Components of net benefit cost (credit):						
Service cost	\$ 53	\$ 52	\$ 40	\$ 1	\$ 1	\$ 1
Interest cost	96	84	88	12	12	13
Expected return on assets	(129)	(149)	(147)	(16)	(20)	(19)
Amortization of prior service cost (credit)	—	—	1	(4)	(4)	(3)
Amortization of net actuarial loss (gain)	54	40	52	(11)	(6)	(6)
Curtailement and settlement loss	—	—	5	—	—	—
Net benefit cost (credit)	74	27	39	(18)	(17)	(14)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net (gain) loss arising during period	(42)	105	17	(17)	(32)	(25)
Amortization or settlement recognition of net actuarial (loss) gain	(54)	(87)	(64)	11	3	6
Amortization of prior service (cost) credit	—	(1)	(1)	2	3	1
Total recognized in total other comprehensive (income) loss	(96)	17	(48)	(4)	(26)	(18)
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	\$ (22)	\$ 44	\$ (9)	\$ (22)	\$ (43)	\$ (32)

Multiemployer Plans

We participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately \$8 million for each of the years

ended December 31, 2019, 2018 and 2017. We consider the overall multi-employer pension plan liability exposure to be immaterial in relation to the value of its total consolidated assets and net income.

Adoption of Accounting Pronouncement

On January 1, 2018, we adopted ASU No. 2017-07, " *Compensation - Retirement Benefits (Topic 715)* ." This ASU requires an employer to disaggregate the service cost component from the other components of net benefit cost, allows only the service cost component of net benefit cost to be eligible for capitalization and establishes how to present the service cost component and the other components of net benefit cost in the income statement. Topic 715 required us to retrospectively reclassify \$15 million of other components of net benefit credits (excluding the service cost component) from "General and administrative" to "Other, net" in our accompanying consolidated statement of income for the year ended December 31, 2017. We prospectively applied Topic 715 related to net benefit costs eligible for capitalization.

11. Stockholders' Equity

Mandatory Convertible Preferred Stock

As of October 26, 2018, all of our issued and outstanding 1,600,000 shares of 9.75% Series A mandatory convertible preferred stock, with a liquidating preference of \$1,000 per share were converted into common stock either at the option of the holders before or automatically on October 26, 2018. Based on the market price of our common stock at the time of conversion, our Series A Preferred Shares converted into approximately 58 million common shares.

Preferred Stock Dividends

Dividends on our mandatory convertible preferred stock were payable on a cumulative basis when, as and if declared by our board of directors (or an authorized committee thereof) at an annual rate of 9.75% of the liquidation preference of \$1,000 per share on January 26, April 26, July 26 and October 26 of each year, commencing on January 26, 2016 to, and including, October 26, 2018. Prior to the October 26, 2018 conversion of our Series A Preferred Shares into common shares, we paid all dividends on our mandatory convertible preferred stock in cash.

Common Equity

As of December 31, 2019, our common equity consisted of our Class P common stock.

On July 19, 2017, our board of directors approved a \$2 billion common share buy-back program that began in December 2017. During the years ended December 31, 2019, 2018 and 2017, we repurchased approximately 0.1 million, 15 million and 14 million, respectively, of our Class P shares for approximately \$2 million, \$273 million and \$250 million, respectively. Since December 2017, in total, we have repurchased approximately 29 million of our Class P shares under the program at an average price of approximately \$18.18 per share for approximately \$525 million.

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 of our Class P common stock having an aggregate offering of up to \$5.0 billion from time to time during the term of this agreement. During the years ended December 31, 2019, 2018 and 2017 we did not issue any Class P common stock under this agreement.

KMI Common Stock Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. The following table provides information about our per share dividends:

	Year Ended December 31,		
	2019	2018	2017
Per common share cash dividend declared for the period	\$ 1.00	\$ 0.80	\$ 0.50
Per common share cash dividend paid in the period	0.95	0.725	0.50

On January 22, 2020, our board of directors declared a cash dividend of \$0.25 per common share for the quarterly period ended December 31, 2019, which is payable on February 18, 2020 to shareholders of record as of February 3, 2020.

Accumulated Other Comprehensive Loss

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss

Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as "Accumulated other comprehensive loss" within "Stockholders' Equity" in our consolidated balance sheets. Changes in the components of our "Accumulated other comprehensive loss" not including non-controlling interests are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total Accumulated other comprehensive loss
Balance at December 31, 2016	\$ (1)	\$ (288)	\$ (372)	\$ (661)
Other comprehensive gain before reclassifications	145	55	40	240
Gain reclassified from accumulated other comprehensive loss	(171)	—	—	(171)
KML IPO	—	44	7	51
Net current-period change in accumulated other comprehensive (loss) income	(26)	99	47	120
Balance at December 31, 2017	(27)	(189)	(325)	(541)
Other comprehensive gain (loss) before reclassifications	111	(89)	(31)	(9)
Losses reclassified from accumulated other comprehensive loss(a)	84	223	22	329
Impact of adoption of ASU 2018-02 (see below)	(4)	(36)	(69)	(109)
Net current-period change in accumulated other comprehensive income (loss)	191	98	(78)	211
Balance at December 31, 2018	164	(91)	(403)	(330)
Other comprehensive (loss) gain before reclassifications	(177)	—	77	(100)
Losses reclassified from accumulated other comprehensive loss(a)	6	91	—	97
Net current-period change in accumulated other comprehensive (loss) income	(171)	91	77	(3)
Balance at December 31, 2019	\$ (7)	\$ —	\$ (326)	\$ (333)

(a) Amounts for foreign currency translation adjustments and pension and other postretirement liability adjustments reflect the deferred losses recognized in income during the year ended December 31, 2018 related to the TMPL Sale. Amount for foreign currency translation adjustments reflect the deferred losses recognized in income during the year ended December 31, 2019 related to the sale of KML.

Noncontrolling Interests

The caption "Noncontrolling interests" in our accompanying consolidated balance sheets consists of interests that we do not own in the following subsidiaries (in millions):

	December 31,	
	2019	2018
KML(a)	\$ —	\$ 514
Others	344	339
	\$ 344	\$ 853

(a) On December 16, 2019, we completed the sale of all the outstanding common equity of KML, including our 70% interest, to Pembina. See Note 3 for more information.

KML Contributions

Restricted Voting Shares

On May 30, 2017 our former indirect subsidiary, KML, issued 102,942,000 restricted voting shares in a public offering listed on the Toronto Stock Exchange. The public ownership of the KML restricted voting shares represented an approximate 30% interest in our Canadian operations and was reflected within "Noncontrolling interests" in our consolidated financial statements as of and for the periods presented after May 30, 2017 through the date of the KML Sale. See Note 3.

Preferred Share Offerings

On August 15, 2017, KML completed an offering of 12,000,000 cumulative redeemable minimum rate reset preferred shares, Series 1 (Series 1 Preferred Shares) on the Toronto Stock Exchange at a price to the public of C\$25.00 per Series 1 Preferred Share for total gross proceeds of C\$300 million (U.S.\$235 million). On December 15, 2017, KML completed an offering of 10,000,000 cumulative redeemable minimum rate reset preferred shares, Series 3 (Series 3 Preferred Shares) on the Toronto Stock Exchange at a price to the public of C\$25.00 per Series 3 Preferred Share for total gross proceeds of C\$250 million (U.S.\$195 million). The net proceeds from the Series 1 and Series 3 Preferred Share offerings of C\$293 million (U.S. \$230 million) and C\$243 million (U.S.\$189 million), respectively, were used by KML to indirectly subscribe for preferred units in KMC LP, which in turn were used by KMC LP to repay the KML Credit Facility indebtedness incurred to, directly or indirectly, finance the development, construction and completion of the TMEP and Base Line Terminal project, and for its general corporate purposes.

KML Distributions

In accordance with KML's dividend policy, KML paid dividends during the years ended December 31, 2019, 2018 and 2017, on its restricted voting shares to the public valued at \$17 million, \$52 million and \$18 million, respectively, of which \$17 million, \$38 million and \$13 million, respectively, was paid in cash. The remaining value of \$14 million and \$5 million for the years ended December 31, 2018 and 2017, respectively, was paid in 1,092,791 and 418,989, respectively, KML restricted voting shares. KML also paid dividends to the public on its preferred shares of \$22 million, \$21 million and \$3 million for the years ended December 31, 2019, 2018 and 2017.

On January 3, 2019, KML distributed approximately \$0.9 billion of the net proceeds from the TMPL Sale to its public held restricted voting shareholders as a return of capital.

Adoption of Accounting Pronouncements

On January 1, 2018, we adopted ASU No. 2017-05, "Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets." This ASU clarifies the scope and application of ASC 610-20 on contracts for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. This ASU also clarifies that the derecognition of all businesses is in the scope of ASC 810 and defines an "in substance nonfinancial asset." We utilized the modified retrospective method to adopt the provisions of this ASU, which required us to apply the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) to contracts that were not completed contracts as of January 1, 2018 through a cumulative adjustment to our "Accumulated deficit" balance. The cumulative effect of the adoption of this ASU was a \$66 million, net of income taxes, adjustment to our beginning "Accumulated deficit" balance as presented in our consolidated statement of stockholders' equity for the year ended December 31, 2018. This ASU also required us to classify EIG Global Energy Partners' (EIG) cumulative contribution to ELC as mezzanine equity, which we have included as "Redeemable Noncontrolling Interest" on our consolidated balance sheets as of December 31, 2019 and 2018, as EIG has the right to redeem their interests for cash under certain conditions.

On January 1, 2018, we adopted ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income." Our accounting policy for the release of stranded tax effects in accumulated other comprehensive income is on an aggregate portfolio basis. This ASU permits companies to reclassify the income tax effects of the 2017 Tax Reform on items within accumulated other comprehensive income to retained earnings. The FASB refers to these amounts as "stranded tax effects." Only the stranded tax effects resulting from the 2017 Tax Reform are eligible for reclassification. The adoption of this ASU resulted in a \$109 million reclassification adjustment of stranded income tax effects from "Accumulated

other comprehensive loss" to "Accumulated deficit" on our consolidated statement of stockholders' equity for the year ended December 31, 2018.

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 joint venture partners of our joint ventures we consolidate, and for periods prior to the sale of KML, our proportional method joint ventures, for which we include our proportionate share of balances and activity in our financial statements. 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 (in millions):

	December 31,	
	2019	2018
Balance sheet location		
Accounts receivable, net	\$ 38	\$ 48
Other current assets	—	2
Deferred charges and other assets	86	55
	\$ 124	\$ 105
Current portion of debt		
Current portion of debt	\$ 6	\$ 6
Accounts payable	23	26
Other current liabilities	3	7
Long-term debt	157	148
Other long-term liabilities and deferred credits	41	34
	\$ 230	\$ 221

	Year Ended December 31,		
	2019	2018	2017
Income statement location			
Revenues	\$ 269	\$ 265	\$ 162
Operating Costs, Expenses and Other			
Costs of sales	\$ 75	\$ 63	\$ 20
Other operating expenses	132	91	100

13. Commitments and Contingent Liabilities

Rights-Of-Way (ROW) Obligations

Our ROW obligations primarily consist of non-lease agreements that existed at the time of Topic 842 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 ROW obligations were \$202 million as of December 31, 2019.

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, 2019 and 2018, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled \$330 million and \$714 million, respectively. December 31, 2019 and 2018 amounts are represented by our proportional share of the debt obligations of three and four equity investees, respectively. Under such guarantees we are

severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. The contingent debt obligations balances as of December 31, 2019 and 2018 included \$128 million and \$147 million, respectively, for 100% guaranteed debt obligations for a subsidiary of Cortez Pipeline Company.

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. Currently, we are not subject to any material requirements to perform under quantifiable arrangements. We are unable to estimate a maximum exposure for our 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.

During the year ended December 31, 2018, due to volatility in certain basis differentials, we discontinued hedge accounting on certain of our crude oil derivative contracts as we did not expect them to be highly effective, for accounting purposes, in offsetting the variability in cash flows. As of December 31, 2018, these hedging relationships had been re-designated as the effectiveness improved to required levels. As the forecasted transactions were still probable, accumulated gains and losses prior to the discontinuance remained in "Accumulated other comprehensive loss" unless earnings were impacted by the forecasted transactions; however, changes in the derivative contracts' fair value subsequent to the discontinuance of hedge accounting and prior to the re-designation were reported in earnings. Upon re-designation, we resumed reporting changes in the derivative contracts' fair value in "Accumulated other comprehensive income."

On January 1, 2019, we adopted ASU No. 2017-12, "*Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*." The ASU better aligns an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. We applied ASU No. 2017-12 using a modified retrospective approach for cash flow and fair value hedges existing at the date of adoption and prospectively for the presentation and disclosure guidance. Our adoption of ASU No. 2017-12 did not have a material impact on our consolidated financial statements.

Energy Commodity Price Risk Management

As of December 31, 2019, 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	(19.6) MMBbl
Crude oil basis	(7.2) MMBbl
Natural gas fixed price	(30.8) Bcf
Natural gas basis	(22.3) Bcf
NGL fixed price	(1.3) MMBbl
Derivatives not designated as hedging contracts	
Crude oil fixed price	(0.8) MMBbl
Crude oil basis	(4.1) MMBbl
Natural gas fixed price	(5.2) Bcf
Natural gas basis	(8.8) Bcf
NGL fixed price	(1.9) MMBbl

As of December 31, 2019, 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 2023.

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, 2019 (in millions):

	Notional amount	Accounting treatment	Maximum term
Derivatives designated as hedging instruments			
Fixed-to-variable interest rate contracts(a)	\$8,725	Fair value hedge	March 2035
Variable-to-fixed interest rate contracts	\$250	Cash flow hedge	January 2023

(a) The principal amount of hedged senior notes consisted of \$1,100 million included in "Current portion of debt" and \$7,625 million included in "Long-term debt" on our accompanying consolidated balance sheet.

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, 2019 (in millions):

	Notional amount	Accounting treatment	Maximum term
Derivatives designated as hedging instruments			
EUR-to-USD cross currency swap contracts(a)	\$1,358	Cash flow hedge	March 2027

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

During the year ended December 31, 2018, we entered into foreign currency swap agreements with a combined notional principal amount of C\$2,450 million (U.S.\$1,888 million). These swaps resulted in our selling fixed C\$ and receiving fixed U.S.\$, effectively hedging the foreign currency risk associated with a substantial portion of our share of the TMPL Sale proceeds which KML distributed on January 3, 2019, at which time the foreign currency swaps expired. These foreign currency swaps were accounted for as net investment hedges as the foreign currency risk was related to our investment in Canadian dollar denominated foreign operations, and the critical risks of the forward contracts coincided with those of the net investment. As a result, the change in fair value of the foreign currency swaps were reflected in the "Foreign currency translation adjustments" section of "Other comprehensive income (loss), net of tax" on our consolidated statements of

comprehensive income. In December 2019, these currency translation adjustments were recognized as a part of the after-tax net gain on the KML and U.S. Cochin Sale. See Note 3.

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 (in millions):

Location		Derivatives Asset		Derivatives Liability	
		December 31,		December 31,	
		2019	2018	2019	2018
		Fair value		Fair value	
Derivatives designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	\$ 31	\$ 135	\$ (43)	\$ (45)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	17	64	(8)	—
Subtotal		48	199	(51)	(45)
Interest rate contracts	Fair value of derivative contracts/(Other current liabilities)	45	12	—	(37)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	313	121	(1)	(78)
Subtotal		358	133	(1)	(115)
Foreign currency contracts	Fair value of derivative contracts/(Other current liabilities)	—	91	(6)	(6)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	46	106	—	—
Subtotal		46	197	(6)	(6)
Total		452	529	(58)	(166)
Derivatives not designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	8	22	(7)	(5)
Total		8	22	(7)	(5)
Total derivatives		\$ 460	\$ 551	\$ (65)	\$ (171)

The following two tables summarize the fair value measurements of our derivative contracts based on the three levels established by the Codification (in millions). 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.

Balance sheet asset fair value measurements by level							
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
As of December 31, 2019							
Energy commodity derivative contracts(a)	\$ 19	\$ 37	\$ —	\$ 56	\$ (19)	\$ (21)	\$ 16
Interest rate contracts	\$ —	\$ 358	\$ —	\$ 358	\$ —	\$ —	\$ 358
Foreign currency contracts	\$ —	\$ 46	\$ —	\$ 46	\$ (6)	\$ —	\$ 40
As of December 31, 2018							
Energy commodity derivative contracts(a)	\$ 28	\$ 193	\$ —	\$ 221	\$ (39)	\$ (25)	\$ 157
Interest rate contracts	\$ —	\$ 133	\$ —	\$ 133	\$ (7)	\$ —	\$ 126
Foreign currency contracts	\$ —	\$ 197	\$ —	\$ 197	\$ (6)	\$ —	\$ 191

Balance sheet liability fair value measurements by level							
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral posted(b)	Net amount
As of December 31, 2019							
Energy commodity derivative contracts(a)	\$ (3)	\$ (55)	\$ —	\$ (58)	\$ 19	\$ —	\$ (39)
Interest rate contracts	\$ —	\$ (1)	\$ —	\$ (1)	\$ —	\$ —	\$ (1)
Foreign currency contracts	\$ —	\$ (6)	\$ —	\$ (6)	\$ 6	\$ —	\$ —
As of December 31, 2018							
Energy commodity derivative contracts(a)	\$ (11)	\$ (39)	\$ —	\$ (50)	\$ 39	\$ —	\$ (11)
Interest rate contracts	\$ —	\$ (115)	\$ —	\$ (115)	\$ 7	\$ —	\$ (108)
Foreign currency contracts	\$ —	\$ (6)	\$ —	\$ (6)	\$ 6	\$ —	\$ —

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps, NGL swaps and crude oil basis swaps.

(b) 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.

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

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2019	2018	2017
Interest rate contracts	Interest, net	\$ 340	\$ (122)	\$ (103)
Hedged fixed rate debt(a)	Interest, net	\$ (353)	\$ 113	\$ 105

(a) As of December 31, 2019, the cumulative amount of fair value hedging adjustments to our hedged fixed rate debt was an increase of \$359 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,		
	2019	2018	2017		2019	2018	2017
Energy commodity derivative contracts	\$ (168)	\$ 201	\$ 37	Revenues—Commodity sales	\$ 16	\$ (59)	\$ 73
				Costs of sales	5	21	14
Interest rate contracts(c)	(1)	3	—	Earnings from equity investments(c)	2	(4)	(5)
Foreign currency contracts	(60)	(59)	190	Other, net	(31)	(67)	186
Total	\$ (229)	\$ 145	\$ 227	Total	\$ (8)	\$ (109)	\$ 268

- (a) We expect to reclassify an approximate \$22 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2019 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 year ended December 31, 2019, we recognized a \$12 million gain associated with a write-down of hedged inventory. During the year ended December 31, 2018, we recognized a \$3 million loss as a result of our equity investment's forecasted transactions being probable of not occurring and a \$21 million gain 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).
- (c) Amounts represent our share of an equity investee's accumulated other comprehensive income (loss).

Derivatives in net investment hedging relationships	Gain/(loss) recognized in OCI on derivative			Location	Gain/(loss) reclassified from Accumulated OCI into income(a)		
	Year Ended December 31,				Year Ended December 31,		
	2019	2018	2017		2019	2018	2017
Foreign currency contracts	\$ (8)	\$ 91	\$ —	(Gain) loss on divestitures and impairments, net	\$ 83	\$ 26	\$ —
Total	\$ (8)	\$ 91	\$ —	Total	\$ 83	\$ 26	\$ —

- (a) During the year ended December 31, 2019, we recognized a \$83 million gain related to the KML and U.S. Cochin Sale. During the year ended December 31, 2018, we recognized a \$26 million gain related to the TMPL Sale. See Note 3.

Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives		
		Year Ended December 31,		
		2019	2018	2017
Energy commodity derivative contracts	Revenues—Commodity sales	\$ 33	\$ (9)	\$ 4
	Costs of sales	(7)	2	—
	Earnings from equity investments(b)	3	—	—
Total(a)		\$ 29	\$ (7)	\$ 4

- (a) The years ended December 31, 2019, 2018 and 2017 include approximate losses of \$8 million and \$4 million, and gains of \$57 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.
- (b) Amounts represent our share of an equity investee's income (loss).

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, 2019 and 2018, we had no outstanding

letters of credit supporting our commodity price risk management program. As of December 31, 2019 and 2018, we had cash margins of \$15 million and \$16 million, respectively, posted by our counterparties with us as collateral and reported within "Other current liabilities" on our accompanying consolidated balance sheets. The balance at December 31, 2019 represents the net of our initial margin requirements of \$6 million, offset by counterparty variation margin requirements of \$21 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, 2019, 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 \$11 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 fee reserving the right to transport or store natural gas in our facilities up to contractually specified capacity levels (referred to as "reservation") and (ii) a fee-based per-unit rate for quantities of natural gas actually transported or injected into/withdrawn from storage. In our firm service contracts we generally promise to provide a single integrated service each day over the life of the contract, which is fundamentally a stand-ready obligation to provide services up to the customer's reservation capacity prescribed in the contract. Our customers have a take-or-pay payment obligation with respect to the fixed reservation fee component, regardless of the quantities they actually transport or store. In other cases, generally described as interruptible service, there is no fixed fee associated with these transportation and storage services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have firm service contracts. We do not have an obligation to perform under interruptible customer arrangements until we accept and schedule the customer's request for periodic 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, we typically promise to transport on a stand-ready basis the customer's minimum volume commitment amount. The customer is obligated to pay for its 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 monthly fee for the portion of storage capacity reserved by the customer and a per-unit rate for actual quantities injected into/withdrawn from storage. The customer is obligated to pay the fixed monthly reservation fee, regardless of whether or not it uses our storage facility (i.e., take-or-pay payment obligation). Non-firm transportation and storage service is provided to our customers when and to the extent we determine the requested capacity is available in our pipeline system and/or terminal storage facility. 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, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts 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 and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. In some cases, the customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

CO₂ Segment

Our crude oil, NGL, CO₂ 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.

Kinder Morgan Canada Segment

On August 31, 2018, the assets comprising the Kinder Morgan Canada business segment were sold; therefore, this segment will not have revenues on a prospective basis (see Note 3). Prior to the sale of these assets, we provided crude oil and refined petroleum transportation services generally as described above for non-firm, interruptible transportation services in our

Products Pipelines business segment. The TMPL regulated tariff was designed to provide revenues sufficient to recover the costs of providing transportation services to shippers, including a return on invested capital. TMPL's revenue was adjusted according to terms prescribed in our toll settlement with shippers as approved by the National Energy Board (NEB). Differences between transportation revenue recognized pursuant to our toll settlement and actual toll receipts were recognized as regulatory assets or liabilities and settled through future tolls.

Disaggregation of Revenues

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

Year ended December 31, 2019						
	Natural Gas Pipelines	Products Pipelines	Terminals	CO ₂	Corporate and Eliminations	Total
Revenues from contracts with customers(a)						
Services						
Firm services(b)	\$ 3,549	\$ 319	\$ 1,012	\$ 1	\$ (4)	\$ 4,877
Fee-based services	780	1,016	560	60	—	2,416
Total services	4,329	1,335	1,572	61	(4)	7,293
Commodity sales						
Natural gas sales	2,603	—	—	1	(9)	2,595
Product sales	805	289	20	1,111	(33)	2,192
Total commodity sales	3,408	289	20	1,112	(42)	4,787
Total revenues from contracts with customers	7,737	1,624	1,592	1,173	(46)	12,080
Other revenues(c)	433	207	442	46	1	1,129
Total revenues	\$ 8,170	\$ 1,831	\$ 2,034	\$ 1,219	\$ (45)	\$ 13,209

Year ended December 31, 2018							
	Natural Gas Pipelines	Products Pipelines	Terminals	CO ₂	Kinder Morgan Canada(d)	Corporate and Eliminations	Total
Revenues from contracts with customers(a)							
Services							
Firm services(b)	\$ 3,387	\$ 376	\$ 983	\$ 2	\$ —	\$ (2)	\$ 4,746
Fee-based services	692	956	584	67	167	—	2,466
Total services	4,079	1,332	1,567	69	167	(2)	7,212
Commodity sales							
Natural gas sales	3,327	—	—	2	—	(11)	3,318
Product sales	1,190	393	20	1,222	—	(37)	2,788
Total commodity sales	4,517	393	20	1,224	—	(48)	6,106
Total revenues from contracts with customers	8,596	1,725	1,587	1,293	167	(50)	13,318
Other revenues(c)	259	162	440	(38)	3	—	826
Total revenues	\$ 8,855	\$ 1,887	\$ 2,027	\$ 1,255	\$ 170	\$ (50)	\$ 14,144

(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) below).

(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 Accounting Standards Codification other than in Topic 606 and primarily include leases of \$951 million and \$868 million and derivatives of \$49 million and \$(133) million for the years ended December 31, 2019 and 2018, respectively. See Notes 14 for additional information related to our derivatives.
- (d) On August 31, 2018, the assets comprising the Kinder Morgan Canada business segment were sold; therefore, this segment does not have results of operations on a prospective basis (see Note 3).

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.

As of December 31, 2019 and 2018, our contract asset balances were \$27 million and \$24 million, respectively. Of the contract asset balance at December 31, 2018, \$31 million was transferred to accounts receivable during the year ended December 31, 2019. As of December 31, 2019 and 2018, our contract liability balances were \$232 million and \$292 million, respectively. Of the contract liability balance at December 31, 2018, \$68 million was recognized as revenue during the year ended December 31, 2019. During the year ended December 31, 2019 our contract liability balance was reduced by \$52 million due to the KML and U.S. Cochin Sale.

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, 2019 that we will invoice or transfer from contract liabilities and recognize in future periods (in millions):

Year	Estimated Revenue	
2020	\$	4,399
2021		3,752
2022		3,099
2023		2,510
2024		2,181
Thereafter		13,301
Total	\$	29,242

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 expedients that we elected to apply, remaining performance obligations for: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation and (ii) contracts with an original expected duration of one year or less.

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 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, propane, ethane, 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. and portions of Canada (prior to the sale of KML in December 2019) that store and handle various commodities including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke; and (ii) Jones Act-qualified tankers;
- CO₂—(i) the production, transportation and marketing of CO₂ to oil fields that use CO₂ 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; and (iii) the ownership and operation of a crude oil pipeline system in West Texas; and
- Kinder Morgan Canada (prior to August 31, 2018)—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. As a result of the TMPL Sale, this segment does not have results of operations on a prospective basis.

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 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.

For segment reporting purposes, effective January 1, 2019, certain assets were transferred among our business segments. As a result, individual segment results for the years ended December 31, 2018 and 2017 and balances as of December 31, 2018 have been reclassified to conform to the current presentation in the following tables. Revenues, Segment EBDA and Assets previously reported (before reclassifications) for the years ended December 31, 2018 and 2017 and as of December 31, 2018 are discussed further in the footnotes to the tables below.

During 2019, 2018 and 2017, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2019	2018	2017
Revenues			
Natural Gas Pipelines			
Revenues from external customers	\$ 8,128	\$ 8,807	\$ 8,502
Intersegment revenues	42	48	22
Products Pipelines	1,831	1,887	1,744
Terminals			
Revenues from external customers	2,031	2,025	1,972
Intersegment revenues	3	2	2
CO ₂	1,219	1,255	1,196
Kinder Morgan Canada	—	170	256
Corporate and intersegment eliminations(a)	(45)	(50)	11
Total consolidated revenues(b)	\$ 13,209	\$ 14,144	\$ 13,705

	Year Ended December 31,		
	2019	2018	2017
Operating expenses(c)			
Natural Gas Pipelines	\$ 4,213	\$ 5,218	\$ 5,371
Products Pipelines	684	748	564
Terminals	888	823	793
CO ₂	496	453	394
Kinder Morgan Canada	—	72	95
Corporate and intersegment eliminations	(1)	(26)	(2)
Total consolidated operating expenses	\$ 6,280	\$ 7,288	\$ 7,215

	Year Ended December 31,		
	2019	2018	2017
Other (income) expense(d)			
Natural Gas Pipelines	\$ (680)	\$ 629	\$ 26
Products Pipelines	—	(2)	—
Terminals	(342)	54	(14)
CO ₂	77	79	(1)
Kinder Morgan Canada	2	(596)	—
Corporate	(2)	—	1
Total consolidated other (income) expense	\$ (945)	\$ 164	\$ 12

	Year Ended December 31,		
	2019	2018	2017
DD&A			
Natural Gas Pipelines	\$ 1,005	\$ 955	\$ 909
Products Pipelines	338	326	310
Terminals	494	489	480
CO ₂	548	473	493
Kinder Morgan Canada	—	29	46
Corporate	26	25	23
Total consolidated DD&A	\$ 2,411	\$ 2,297	\$ 2,261

	Year Ended December 31,		
	2019	2018	2017
Earnings (loss) from equity investments and amortization of excess cost of equity investments, including loss on impairments of equity investments			
Natural Gas Pipelines	\$ (101)	\$ 410	\$ 258
Products Pipelines	63	56	43
Terminals	23	22	24
CO ₂	33	34	42
Total consolidated equity earnings	\$ 18	\$ 522	\$ 367

	Year Ended December 31,		
	2019	2018	2017
Other, net-income (expense)			
Natural Gas Pipelines	\$ 53	\$ 39	\$ 44
Products Pipelines	6	2	4
Terminals	(5)	3	8
Kinder Morgan Canada	—	26	25
Corporate	21	37	16
Total consolidated other, net-income (expense)	\$ 75	\$ 107	\$ 97

	Year Ended December 31,		
	2019	2018	2017
Segment EBDA(e)			
Natural Gas Pipelines	\$ 4,661	\$ 3,540	\$ 3,478
Products Pipelines	1,225	1,209	1,237
Terminals	1,506	1,175	1,227
CO ₂	681	759	847
Kinder Morgan Canada	(2)	720	186
Total Segment EBDA(f)	8,071	7,403	6,975
DD&A	(2,411)	(2,297)	(2,261)
Amortization of excess cost of equity investments	(83)	(95)	(61)
General and administrative and corporate charges	(611)	(588)	(660)
Interest, net	(1,801)	(1,917)	(1,832)
Income tax expense	(926)	(587)	(1,938)
Total consolidated net income	\$ 2,239	\$ 1,919	\$ 223

	Year Ended December 31,		
	2019	2018	2017
Capital expenditures			
Natural Gas Pipelines	\$ 1,377	\$ 1,565	\$ 1,349
Products Pipelines	175	199	149
Terminals	347	386	893
CO ₂	349	397	436
Kinder Morgan Canada	—	332	338
Corporate	22	25	23
Total consolidated capital expenditures	\$ 2,270	\$ 2,904	\$ 3,188

	December 31,	
	2019	2018
Investments		
Natural Gas Pipelines	\$ 6,991	\$ 6,709
Products Pipelines	491	488
Terminals	251	268
CO ₂	26	16
Total consolidated investments	\$ 7,759	\$ 7,481

	December 31,	
	2019	2018
Assets		
Natural Gas Pipelines	\$ 50,310	\$ 50,261
Products Pipelines	9,468	9,598
Terminals	8,890	9,415
CO ₂	3,523	3,928
Corporate assets(g)	1,966	5,664
Total consolidated assets(h)	\$ 74,157	\$ 78,866

- (a) 2017 amount includes a management fee of \$35 million for services we perform as operator of an equity investee.
- (b) Revenues previously reported (before reclassifications) for the year ended December 31, 2018 were \$9,015 million, \$1,713 million, \$2,019 million and \$(28) million and for the year ended December 31, 2017 were \$8,618 million, \$1,661 million, \$1,966 million and \$8 million for the Natural Gas Pipelines, Products Pipelines and Terminals business segments, and the Corporate and intersegment eliminations, respectively.
- (c) Includes costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
- (d) Includes (gain) loss on divestitures and impairments, net and other income, net.
- (e) Includes revenues, earnings from equity investments, and other, net, less operating expenses, (gain) loss on divestitures and impairments, net and other income, net.
- (f) Segment EBDA previously reported (before reclassifications) for the year ended December 31, 2018 were \$3,580 million, \$1,173 million and \$1,171 million and for the year ended December 31, 2017 were \$3,487 million, \$1,231 million and \$1,224 million for the Natural Gas Pipelines, Products Pipelines and Terminals business segments, respectively.
- (g) 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 activity) not allocated to our reportable segments.
- (h) Assets previously reported as of December 31, 2018 were \$51,562 million, \$8,429 million and \$9,283 million for the Natural Gas Pipelines, Products Pipelines and Terminals business segments, respectively. The reclassification included a transfer of \$450 million of goodwill from the Natural Gas Pipelines Non-Regulated reporting unit to the Products Pipelines reporting unit.

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 (in millions):

	Year Ended December 31,		
	2019	2018	2017
Revenues from external customers			
U.S.	\$ 12,833	\$ 13,596	\$ 13,073
Canada	300	447	503
Mexico and other foreign	76	101	129
Total consolidated revenues from external customers	\$ 13,209	\$ 14,144	\$ 13,705

	December 31,		
	2019	2018	2017
Long-term assets, excluding goodwill and other intangibles			
U.S.	\$ 46,709	\$ 47,468	\$ 47,928
Canada	1	748	3,071
Mexico and other foreign	82	83	80
Total consolidated long-lived assets	\$ 46,792	\$ 48,299	\$ 51,079

17. Leases

Effective January 1, 2019, we adopted ASU No. 2016-02 "Leases (Topic 842)" and the series of related Accounting Standards Updates that followed (collectively referred to as "Topic 842"). The most significant changes under the new guidance include clarification of the definition of a lease, and the requirements for lessees to recognize a ROU asset and a lease liability for all qualifying leases with terms longer than twelve months in the consolidated balance sheet. In addition, under Topic 842, additional disclosures are required to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.

We elected the practical expedient available to us under ASU 2018-11 "Leases: Targeted Improvements," which allows us to apply the transition provision for Topic 842 at our adoption date instead of at the earliest comparative period presented in our financial statements. Therefore, we recognized and measured leases existing at January 1, 2019 but without retrospective application. In addition, we elected the practical expedient permitted under the transition guidance related to land easements which allows us to carry forward our historical accounting treatment for land easements on existing agreements upon adoption. We also elected all other available practical expedients except the hindsight practical expedient.

The impact of Topic 842 on our consolidated balance sheet beginning January 1, 2019 was through the recognition of ROU assets and lease liabilities for operating leases, while our accounting for finance leases remained substantially unchanged. Our finance leases were immaterial prior to the adoption of Topic 842, and no change was made to the classification for these leases. Amounts recognized at January 1, 2019 for operating leases were as follows (in millions):

	January 1, 2019	
ROU assets	\$	696
Short-term lease liability		52
Long-term lease liability		644

No impact was recorded to our consolidated income statement for the year ended December 31, 2019 or beginning accumulated deficit for Topic 842.

Refer to Note 2 "Summary of Significant Accounting Policies—Leases" for a description of accounting for leases.

Lessee

Following are components of our lease cost (in millions):

	Year ended December 31, 2019	
Operating leases	\$	136
Short-term and variable leases		92
Total lease cost(a)	\$	228

(a) Includes \$46 million of capitalized lease costs.

Other information related to our operating leases are as follows (in millions, except lease term and discount rate):

	Year ended December 31, 2019	
Operating cash flows from operating leases	\$	(182)
Investing cash flows from operating leases		(46)
ROU assets obtained in exchange for operating lease obligations, net of retirements adjusted for currency conversion		102
Amortization of ROU assets		75
Removal of ROU assets and liabilities associated with the KML and U.S. Cochin Sale		(394)
Weighted average remaining lease term		13.40 years
Weighted average discount rate		4.31%

Amounts recognized in the accompanying consolidated balance sheet are as follows (in millions):

Lease Activity	Balance sheet location	December 31, 2019	
ROU assets	Deferred charges and other assets	\$	329
Short-term lease liability	Other current liabilities		40
Long-term lease liability	Other long-term liabilities and deferred credits		289
Finance lease assets	Property, plant and equipment, net		2
Finance lease liabilities	Long-term debt—Outstanding		2

Operating lease liabilities under non-cancellable leases (excluding short-term leases) as of December 31, 2019 are as follows (in millions):

Year	Commitment
2020	\$ 55
2021	45
2022	38
2023	32
2024	30
Thereafter	267
Total lease payments	467
Less: Interest	(138)
Present value of lease liabilities	\$ 329

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.

Commitment Obligations Prior to January 1, 2019 Under ASC 840

Under the transition provision of Topic 842, we elected the effective date transition option. Following is the additional required transition disclosure for undiscounted future gross minimum operating lease payments and ROW obligations as of December 31, 2018 under ASC 840 (in millions):

	Leases(a)	ROW(b)	Total(c)
2019	\$ 90	\$ 25	\$ 115
2020	75	25	100
2021	70	25	95
2022	65	26	91
2023	59	25	84
Thereafter	771	88	859
Total payments	\$ 1,130	\$ 214	\$ 1,344

(a) Total future minimum lease obligations include \$695 million for assets included in the KML and U.S. Cochin Sale (see Note 3).

(b) Refer to Note 13 for additional information regarding our ROW obligations as of December 31, 2019.

(c) This table has been revised from the previously reported December 31, 2018 future gross minimum rental commitments under our operating leases and ROW obligations table in our 2018 Form 10-K to (i) separately present lease and ROW obligations and (ii) to correct amounts previously reported to include an additional \$482 million of undiscounted future lease payments, primarily in the "Thereafter" amount associated with the 2018 extension of KML's, Edmonton South tank lease through December 2038. As of December 31, 2019, we no longer have an obligation for this lease as the obligation was transferred to Pembina in the KML and U.S. Cochin Sale.

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 contingencies where an adverse outcome may be material or, in the judgment of management, we conclude the matter should otherwise be disclosed.

FERC Proceedings

FERC Rulemaking on Tax Cuts and Jobs Act for Jurisdictional Natural Gas Pipelines

In July 2018, the FERC issued an order requiring an informational filing by interstate natural gas pipelines on a new Form 501-G, evaluating the impact of the 2017 Tax Reform and the Revised Tax Policy on tax allowances for the pipelines. KMI and certain of its pipeline affiliates successfully worked with their shippers to achieve settlements without the need for litigation or any additional intervention by the FERC. The FERC approved settlements filed by EPNG, SNG, TGP, Young Gas Storage, and Bear Creek Storage Company, L.L.C. and terminated all of our remaining 501-G proceedings without taking further action. Accordingly, our 501-G exposure has been resolved.

FERC Inquiry Regarding the Commission's Policy for Determining Return on Equity

On March 21, 2019, the FERC issued a notice of inquiry (NOI) seeking comments regarding whether the FERC should revise its policies for determining the base return on equity (ROE) used in setting cost of service rates charged by jurisdictional public utilities and interstate natural gas and liquids pipelines. The NOI sought comment on whether any aspects of the existing methodologies used by the FERC to set an ROE for a regulated entity should be changed, whether the ROE methodology should be the same across all three industries, and whether alternative methodologies should be considered. Comments were filed by industry groups, pipeline companies and shippers for review and evaluation by the FERC and there is no deadline or requirement for the FERC to take action on this matter.

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing shipper-initiated proceedings at the FERC. These include IS08-390, filed in June 2008, in which various shippers are challenging SFPP's West Line rates (on appeal to the D.C. Circuit Court); IS09-437, filed in July 2009, in which various shippers are challenging SFPP's East Line rates (pending before the FERC on rehearing); OR11-13/16/18, filed in June 2011, in which various shippers are seeking to challenge SFPP's North Line, Oregon Line, and West Line rates (pending before the FERC for an order on the complaint); OR14-35/36, filed in June 2014, in which various shippers are challenging SFPP's index increases in 2012 and 2013 (dismissed by the FERC, but remanded back to the FERC from the D.C. Circuit for further consideration); OR16-6, filed in December 2015, in which various shippers are challenging SFPP's East line rates (pending before the FERC for an order on the initial decision); and OR19-21/33/37, filed beginning in April 2019, in which various shippers are challenging SFPP's index increases in 2018 (pending before the FERC for an order on the complaints). In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP's index-based rate increases. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. If the shippers prevail on their arguments or claims, they would be entitled to seek reparations for the two year period preceding the filing date of their complaints (OR cases) and/or prospective refunds in protest cases from the date of protest (IS cases), and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

SFPP paid refunds to shippers in May 2019, in the IS08-390 proceeding as ordered by the FERC based on its denial of an income tax allowance. With respect to the various SFPP related complaints and protest proceedings at the FERC (including IS08-390), we estimate that the shippers are seeking approximately \$50 million in annual rate reductions and approximately \$400 million in refunds. Management believes SFPP has meritorious arguments supporting SFPP's rates and intends to vigorously defend SFPP against these complaints and protests. However, to the extent the shippers are successful in one or more of the complaints or protest proceedings, SFPP estimates that applying the principles of FERC precedent, as applicable, as well as the compliance filing methodology recently approved by the FERC to pending SFPP cases would result in rate reductions and refunds substantially lower than those sought by the shippers.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that it will apply its findings in Opinion 517-A to the same issues in the 2010 rate case. All refund obligations related to the 2008 rate case were satisfied in 2015. EPNG sought federal appellate review of Opinion 517-A. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates, and required EPNG to file revised pro forma

recalculated rates consistent with the terms of Opinions 517-A and 528-A. On May 3, 2018, the FERC issued Opinion 528-B upholding its decisions in Opinion 528-A and requiring EPNG to implement the rates required by its rulings and provide refunds within 60 days. On July 2, 2018, EPNG reported to the FERC the refund calculations, and that the refunds had been provided as ordered. Also on July 2, 2018, EPNG initiated appellate review of Opinions 528, 528-A and 528-B. On August 23, 2018, the reviewing court established a briefing schedule and consolidated EPNG's appeal from the 2008 rate case, EPNG's appeal from the 2010 rate case, and the intervenors' delayed appeal in the 2010 rate case. In accordance with that schedule, briefing has been completed and oral argument was rescheduled at the FERC's request to March 13, 2020.

Other Commercial Matters

Gulf LNG Facility Disputes

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that was not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA sought declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have "frustrated the essential purpose" of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC "in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate" the agreement. On June 29, 2018, the arbitration panel delivered its Award, and the panel's ruling called for the termination of the agreement and Eni USA's payment of compensation to GLNG. The Award resulted in our recording a net loss in the second quarter of 2018 of our equity investment in GLNG due to a non-cash impairment of our investment in GLNG partially offset by our share of earnings recognized by GLNG. On September 25, 2018, GLNG filed a lawsuit against Eni USA in the Delaware Court of Chancery to enforce the Award. On February 1, 2019, the Court of Chancery issued a Final Order and Judgment confirming the Award, which was paid by Eni USA on February 20, 2019.

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 entered into by Eni S.p.A. in connection with the terminal use agreement. On December 12, 2018, Eni S.p.A. filed a counterclaim seeking unspecified damages from GLNG.

On June 3, 2019, Eni USA filed a second Notice of Arbitration against GLNG asserting the same breach of contract claims that had been asserted in the first arbitration and alleging that GLNG negligently misrepresented certain facts or contentions in the first arbitration. By its second Notice of Arbitration, Eni USA seeks to recover as damages some or all of the payments made by Eni USA to satisfy the Final Order and Judgment of the Court of Chancery. In response to the second Notice of Arbitration, GLNG filed a complaint with the Court of Chancery together with a motion seeking to permanently enjoin the arbitration. On January 10, 2020, the Court of Chancery entered an Order and Final Judgment granting GLNG's motion to enjoin arbitration of the negligent misrepresentation claim, but denying the motion to enjoin arbitration of the breach of contract claims. GLNG filed a notice of appeal of the Final Judgment.

On December 20, 2019, GLNG's remaining customer, Angola LNG Supply Services LLC (ALSS), filed a Notice of Arbitration seeking a declaration that its terminal use agreement should be deemed terminated as of March 1, 2016 on substantially the same terms and conditions as set forth in the arbitration award pertaining to Eni USA. ALSS also seeks a declaration that activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC in connection with the pursuit of an LNG liquefaction export project have given rise to a contractual right on the part of ALSS to terminate the agreement. ALSS also seeks a monetary award directing GLNG to reimburse ALSS for all reservation charges and operating fees paid by ALSS after December 31, 2016 plus interest.

GLNG intends to continue to vigorously prosecute and defend all of the foregoing proceedings.

Price Reporting Litigation

Beginning in 2003, several lawsuits were filed by purchasers of natural gas against El Paso Corporation, El Paso Marketing L.P. and numerous other energy companies based on a claim under state antitrust law that such defendants conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. All of the cases have been settled or dismissed, including the settlement of the final Wisconsin class action lawsuit which was approved by the U.S. District Court in Nevada on August 5, 2019 on terms that were not material to our business.

Continental Resources, Inc. v. Hiland Partners Holdings, LLC

On December 8, 2017, Continental Resources, Inc. (CLR) filed an action in Garfield County, Oklahoma state court alleging 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 North Dakota counties). CLR also alleged fraud, maintaining that Hiland Partners promised the construction of several additional facilities to process the gas without an intention to build the facilities. Hiland Partners denied these allegations, but the parties entered into a settlement agreement in June 2018, under which CLR agreed to release all of its claims in exchange for Hiland Partners' construction of 10 infrastructure projects by November 1, 2020. CLR now seeks leave to file an amended petition in which it asserts that Hiland Partners' failure to construct certain facilities by specific dates nullifies the release contained in the settlement agreement. CLR's amended petition makes additional claims under both the GPA and a May 8, 2008 gas purchase contract covering additional North Dakota counties, including CLR's contention that Hiland Partners is not allowed to deduct third-party processing fees from the gas purchase price. CLR seeks damages in excess of \$225 million. Hiland Partners denies these claims and will vigorously defend against any action in which they are asserted.

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.

General

As of December 31, 2019 and 2018, our total reserve for legal matters was \$203 million and \$207 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 federal, state and local 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 CO₂ 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, 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, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations, including alleged violations of the Risk Management Program, and leak detection and repair requirements of the Clean Air Act. 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, individually or in the aggregate, will be material. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the remediation.

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, NGL, natural gas and CO₂.

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. The cost for the final remedy is estimated by the EPA to be approximately \$1.1 billion and active cleanup is expected to take as long as 13 years to complete. KMLT, KMBT, and 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 acquired from GATX Terminals Corporation) and KMBT (in connection with its ownership or operation of two facilities). Our share of responsibility for Portland Harbor Superfund Site 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. 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 site. In addition to CERCLA cleanup costs, we are reviewing and will attempt to settle, if possible, natural resource damage (NRD) claims asserted by state and federal trustees following their natural resource assessment of the site. At this time, we are unable to reasonably estimate the extent of our potential NRD liability.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately 20 uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a PRP within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting environmental assessments of the mines and the immediate vicinity. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines, given the U.S. is the owner of the Navajo Reservation, the U.S.'s exploration and reclamation activities at the mines, and the pervasive control of such federal agencies over all aspects of the nuclear weapons program. After a trial which concluded in March 2019, the U.S. District Court issued an order on April 16, 2019 that allocated 35% of past and future response costs to the U.S. The decision was not appealed by any party. The decision does not provide or establish the scope of a remedial plan with respect to the sites, nor does it establish the total cost for addressing the sites, all of which remain to be determined in subsequent proceedings and adversarial actions, if necessary, with the EPA. Until such issues are determined, we are unable to reasonably estimate the extent of our potential liability. Because costs associated with any remedial plan approved by the EPA are expected to be spread over at least several years, we do not anticipate that this decision will have a material adverse impact to our business.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved 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. It has been alleged that EPEC Polymers and EPEC Oil Trust may be PRPs under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) with the EPA which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 44 cooperating parties, referred to as the Cooperating Parties Group (CPG), which is directing and funding the AOC work required by the EPA. Under the first AOC, the CPG submitted draft remedial investigation and feasibility studies (RI/FS) of the Site to the EPA in 2015, and EPA approval remains pending. Under the second AOC, the CPG conducted a CERCLA removal action at the Passaic River Mile 10.9, and is obligated to conduct EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with these two AOCs.

On March 4, 2016, the EPA issued its Record of Decision (ROD) for the lower eight miles of the Site. At that time the final cleanup plan in the ROD was estimated by the EPA to cost \$1.7 billion. On October 5, 2016, the EPA entered into an AOC with Occidental Chemical Company (OCC), a member of the PRP group requiring OCC to spend an estimated \$165 million to perform engineering and design work necessary to begin the cleanup of the lower eight miles of the Site. The design work is underway. Initial expectations were that the design work would take four years to complete. The cleanup is expected to take at least six years to complete once it begins. On June 30, 2018 and July 13, 2018, respectively, OCC filed two separate lawsuits in the U.S. District Court for the District of New Jersey seeking cost recovery and contribution under CERCLA from more than 120 defendants, including EPEC Polymers. OCC alleges that each defendant is responsible to reimburse OCC for a proportionate share of the \$165 million OCC is required to spend pursuant to its AOC. EPEC Polymers was dismissed without prejudice from the lawsuit on August 8, 2018.

In addition, the EPA and numerous PRPs, including EPEC Polymers, are engaged in an allocation process for the implementation of the remedy for the lower eight miles of the Site. There remains significant uncertainty as to the

implementation and associated costs of the remedy set forth in the ROD. There is also uncertainty as to the impact of the EPA FS directive for the upper nine miles of the Site not subject to the lower eight mile ROD. In a letter dated October 10, 2018, the EPA directed the CPG to prepare a streamlined FS for the Site that evaluates interim remedy alternatives for sediments in the upper nine miles of the Site. Until this FS is completed and the RI/FS is finalized and allocations are determined, the scope of potential EPA claims for the Site and liability therefor are not reasonably estimable.

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). The plaintiffs allege the defendants' operations caused substantial damage to the coastal waters of Louisiana and nearby lands, including marsh (Coastal Zone). The alleged damages include erosion of property within the Coastal Zone, and discharge of pollutants that are alleged to have adversely impacted the Coastal Zone, including plants and wildlife. The plaintiffs seek, among other relief, unspecified money damages, attorneys' fees, interest, and payment of costs necessary to restore the affected Coastal Zone to its original condition. The Louisiana Department of Natural Resources (LDNR) and the Louisiana Attorney General (LAG) routinely intervene in these cases, and we expect the LDNR and LAG to intervene in any additional cases that may be filed. 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 that those operations caused substantial damage to the Coastal Zone. Plaquemines Parish seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to remediate, restore, vegetate and detoxify the affected Coastal Zone property. In 2016, the LAG and LDNR intervened in the lawsuit. In May 2018, the case was removed to the U.S. District Court for the Eastern District of Louisiana on several grounds including federal officer liability. Plaquemines Parish, along with the intervenors, moved to remand the case to the state district court. On May 28, 2019, the case was remanded to the state district court for Plaquemines Parish. At the same time, the U.S. District Court certified the federal officer liability jurisdiction issue for review by the U.S. Fifth Circuit Court of Appeals and on June 11, 2019, the U.S. District Court stayed the remand order pending the outcome of that review. The case is effectively stayed pending resolution of the federal officer liability issue by the Court of Appeals. Until these and other issues are determined, we are not able to reasonably estimate the extent of our potential liability, if any. We will continue 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 Zone. Orleans seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to remediate, restore, vegetate and detoxify the affected Coastal Zone property. On April 5, 2019, the case was removed to the U.S. District Court for the Eastern District of Louisiana. On May 28, 2019, Orleans moved to remand the case to the state district court. On January 30, 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. Until these and other issues are determined, we are not able to reasonably estimate the extent of our potential liability, if any. We will continue to vigorously defend this case.

Louisiana Landowner Coastal Erosion Litigation

Beginning in January 2015, several private landowners in Louisiana, as plaintiffs, filed separate lawsuits in state district courts in Louisiana against a number of oil and gas pipeline companies, including two cases against TGP, two cases against SNG, and two cases against both TGP and SNG. In these cases, the plaintiffs allege that the defendants failed to properly maintain pipeline canals and canal banks on their property, which caused the canals to erode and widen and resulted in substantial land loss, including significant damage to the ecology and hydrology of the affected property, and damage to timber and wildlife. The plaintiffs allege that the defendants' conduct constitutes a breach of the subject right of way agreements, is inconsistent with prudent operating practices, violates Louisiana law, and that defendants' failure to maintain canals and canal banks constitutes negligence and trespass. The plaintiffs seek, among other relief, unspecified money damages, attorneys' fees, interest, and payment of costs necessary to return the canals and canal banks to their as-built conditions and restore and remediate the affected property. The plaintiffs allege that the defendants are obligated to restore and remediate the affected

property without regard to the value of the property. The plaintiffs also seek a declaration that the defendants are obligated to take steps to maintain canals and canal banks going forward. In one case filed by Vintage Assets, Inc. and several landowners against SNG, TGP, and another defendant that was tried in 2017 to the U.S. District Court for the Eastern District of Louisiana, \$80 million was sought in money damages, including recovery of litigation costs, damages for trespass, and money damages associated with an alleged loss of natural resources and projected reconstruction cost of replacing or restoring wetlands. On May 4, 2018, the District Court entered a judgment dismissing the tort and negligence claims against all of the defendants, and dismissing certain of the contract claims against TGP. In ruling in favor of the plaintiffs on the remaining contract claims, the District Court ordered the defendants to pay \$1,104 in money damages, and issued a permanent injunction ordering the defendants to restore a total of 9.6 acres of land and maintain certain canals at widths designated by the right of way agreements in effect. The Court stayed the judgment and the injunction pending appeal. The parties each filed a separate appeal to the U.S. Court of Appeals for the Fifth Circuit. On September 13, 2018, the third-party defendant filed a motion to vacate the judgment and dismiss all of the appeals for lack of subject matter jurisdiction. On October 2, 2018 the Court of Appeals dismissed the appeals and on April 17, 2019 the case was remanded to the state district court for Plaquemines Parish, Louisiana for further proceedings. The case is set for trial April 27, 2020. We will continue to vigorously defend these cases.

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, financial position, results of operations or cash flows. As of December 31, 2019 and 2018, we have accrued a total reserve for environmental liabilities in the amount of \$259 million and \$271 million, respectively. In addition, as of December 31, 2019 and 2018, we have recorded a receivable of \$15 million and \$13 million, respectively, for expected cost recoveries that have been deemed probable.

19. Recent Accounting Pronouncements

Accounting Standards Updates

ASU No. 2016-13

On June 16, 2016, the FASB issued ASU No. 2016-13, "*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*." This ASU modifies the impairment model for most financial assets and certain other instruments. For trade and other receivables, held-to-maturity debt securities, loans and other instruments, entities will be required to utilize a new forward-looking "expected loss" methodology that generally will result in the earlier recognition of allowance for losses. ASU No. 2016-13 was effective January 1, 2020. We adopted ASU 2016-13 with no material impact to our financial statements.

ASU No. 2017-04

On January 26, 2017, the FASB issued ASU No. 2017-04, "*Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*." This ASU simplifies the accounting for goodwill impairment by removing Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. Goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU No. 2017-04 was effective January 1, 2020. We adopted ASU 2017-04 with no material impact to our financial statements.

ASU No. 2018-13

On August 28, 2018, the FASB issued ASU No. 2018-13, "*Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement*." This ASU amends existing fair value measurement disclosure requirements by adding, changing, or removing certain disclosures. ASU No. 2018-13 was effective January 1, 2020. We adopted ASU 2018-13 with no material impact to our financial statements.

ASU No. 2018-14

On August 28, 2018, the FASB issued ASU No. 2018-14, "*Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans*." This ASU amends existing annual disclosure requirements applicable to all employers that sponsor defined benefit pension and other postretirement plans by adding, removing, and clarifying certain disclosures. ASU No. 2018-14 will be effective for us

for the fiscal year ending December 31, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

20. Guarantee of Securities of Subsidiaries

KMI, along with its direct subsidiary KMP, are issuers of certain public debt securities. KMI, KMP and substantially all of KMI's wholly owned domestic subsidiaries, 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, the parent issuer, subsidiary issuer and other subsidiaries are all guarantors of each series of public debt. As a result of the cross guarantee agreement, a holder of any of the guaranteed public debt securities issued by KMI or KMP are in the same position with respect to the net assets, income and cash flows of KMI and the Subsidiary Issuer and Guarantors. The only amounts that are not available to the holders of each of the guaranteed public debt securities to satisfy the repayment of such securities are the net assets, income and cash flows of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of December 31, 2019, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had \$13,264 million, \$16,610 million, and \$2,535 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2019 condensed consolidating balance sheet are approximately \$168 million of other financing obligations that are not subject to the cross guarantee agreement.

The accounts within the Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, Subsidiary Guarantors and Subsidiary Non-Guarantors are presented using the equity method of accounting for investments in subsidiaries, including subsidiaries that are guarantors and non-guarantors, for purposes of these condensed consolidating financial statements only. These intercompany investments and related activity eliminate in consolidation and are presented separately in the accompanying condensed consolidating balance sheets and statements of income and cash flows.

A significant amount of each Issuers' income and cash flow is generated by its respective subsidiaries. As a result, the funds necessary to meet its debt service and/or guarantee obligations are provided in large part by distributions or advances it receives from its respective subsidiaries. We utilize a centralized cash pooling program among our majority-owned and consolidated subsidiaries, including the Subsidiary Issuers and Guarantors and Subsidiary Non-Guarantors. The following condensed consolidating statements of cash flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities.

**Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2019
(In Millions)**

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	\$ —	\$ —	\$ 12,016	\$ 1,290	\$ (97)	\$ 13,209
Operating Costs, Expenses and Other						
Costs of sales	—	—	3,160	154	(51)	3,263
Depreciation, depletion and amortization	20	—	2,114	277	—	2,411
Other operating expense	—	1	2,248	459	(46)	2,662
Total Operating Costs, Expenses and Other	20	1	7,522	890	(97)	8,336
Operating (Loss) Income	(20)	(1)	4,494	400	—	4,873
Other Income (Expense)						
Earnings from consolidated subsidiaries	3,690	3,948	857	98	(8,593)	—
Earnings from equity investments	—	—	101	—	—	101
Interest, net	(757)	(2)	(1,019)	(23)	—	(1,801)
Amortization of excess cost of equity investments and other, net	(15)	(2)	(10)	19	—	(8)
Income Before Income Tax	2,898	3,943	4,423	494	(8,593)	3,165
Income Tax Expense	(708)	(3)	(56)	(159)	—	(926)
Net Income	2,190	3,940	4,367	335	(8,593)	2,239
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(49)	(49)
Net Income Attributable to Controlling Interests	\$ 2,190	\$ 3,940	\$ 4,367	\$ 335	\$ (8,642)	\$ 2,190
Net Income	\$ 2,190	\$ 3,940	\$ 4,367	\$ 335	\$ (8,593)	\$ 2,239
Total other comprehensive (loss) income	(3)	28	(51)	224	(184)	14
Comprehensive income	2,187	3,968	4,316	559	(8,777)	2,253
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(66)	(66)
Comprehensive income attributable to controlling interests	\$ 2,187	\$ 3,968	\$ 4,316	\$ 559	\$ (8,843)	\$ 2,187

**Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2018
(In Millions)**

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	\$ —	\$ —	\$ 12,767	\$ 1,526	\$ (149)	\$ 14,144
Operating Costs, Expenses and Other						
Costs of sales	—	—	4,247	277	(103)	4,421
Depreciation, depletion and amortization	19	—	1,971	307	—	2,297
Other operating (income) expense	(39)	1	3,693	23	(46)	3,632
Total Operating Costs, Expenses and Other	(20)	1	9,911	607	(149)	10,350
Operating Income (Loss)	20	(1)	2,856	919	—	3,794
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,760	2,533	599	62	(5,954)	—
Earnings from equity investments	—	—	617	—	—	617
Interest, net	(780)	(8)	(1,090)	(39)	—	(1,917)
Amortization of excess cost of equity investments and other, net	27	—	(18)	3	—	12
Income Before Income Tax	2,027	2,524	2,964	945	(5,954)	2,506
Income Tax (Expense) Benefit	(418)	68	(61)	(176)	—	(587)
Net Income	1,609	2,592	2,903	769	(5,954)	1,919
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(310)	(310)
Net Income Attributable to Controlling Interests	1,609	2,592	2,903	769	(6,264)	1,609
Preferred Stock Dividends	(128)	—	—	—	—	(128)
Net Income Available to Common Shareholders	\$ 1,481	\$ 2,592	\$ 2,903	\$ 769	\$ (6,264)	\$ 1,481
Net Income	\$ 1,609	\$ 2,592	\$ 2,903	\$ 769	\$ (5,954)	\$ 1,919
Total other comprehensive income	320	290	280	136	(688)	338
Comprehensive income	1,929	2,882	3,183	905	(6,642)	2,257
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(328)	(328)
Comprehensive income attributable to controlling interests	\$ 1,929	\$ 2,882	\$ 3,183	\$ 905	\$ (6,970)	\$ 1,929

**Condensed Consolidating Statements of Income and Comprehensive Income
for the Year Ended December 31, 2017
(In Millions)**

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	\$ 35	\$ —	\$ 12,202	\$ 1,614	\$ (146)	\$ 13,705
Operating Costs, Expenses and Other						
Costs of sales	—	—	4,124	322	(101)	4,345
Depreciation, depletion and amortization	16	—	1,933	312	—	2,261
Other operating expense	78	1	3,014	522	(45)	3,570
Total Operating Costs, Expenses and Other	94	1	9,071	1,156	(146)	10,176
Operating (Loss) Income	(59)	(1)	3,131	458	—	3,529
Other Income (Expense)						
Earnings from consolidated subsidiaries	3,575	2,681	419	59	(6,734)	—
Earnings from equity investments	—	—	428	—	—	428
Interest, net	(701)	7	(1,104)	(34)	—	(1,832)
Amortization of excess cost of equity investments and other, net	2	—	13	21	—	36
Income Before Income Tax	2,817	2,687	2,887	504	(6,734)	2,161
Income Tax (Expense) Benefit	(2,634)	(5)	237	464	—	(1,938)
Net Income	183	2,682	3,124	968	(6,734)	223
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(40)	(40)
Net Income Attributable to Controlling Interests	183	2,682	3,124	968	(6,774)	183
Preferred Stock Dividends	(156)	—	—	—	—	(156)
Net Income Available to Common Shareholders	\$ 27	\$ 2,682	\$ 3,124	\$ 968	\$ (6,774)	\$ 27
Net Income	\$ 183	\$ 2,682	\$ 3,124	\$ 968	\$ (6,734)	\$ 223
Total other comprehensive income	69	194	217	160	(525)	115
Comprehensive income	252	2,876	3,341	1,128	(7,259)	338
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(86)	(86)
Comprehensive income attributable to controlling interests	\$ 252	\$ 2,876	\$ 3,341	\$ 1,128	\$ (7,345)	\$ 252

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

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	\$ 2	\$ —	\$ —	\$ 183	\$ —	\$ 185
Other current assets - affiliates	5,249	4,497	30,565	1,105	(41,416)	—
All other current assets	105	39	1,820	1,106	(17)	3,053
Property, plant and equipment, net	218	—	29,997	6,204	—	36,419
Investments	664	—	7,004	91	—	7,759
Investments in subsidiaries	46,873	44,485	5,221	4,449	(101,028)	—
Goodwill	13,721	22	5,167	2,541	—	21,451
Notes receivable from affiliates	912	20,323	453	1,325	(23,013)	—
Deferred income taxes	2,495	—	—	—	(1,638)	857
Other non-current assets	677	223	3,820	96	(383)	4,433
Total assets	\$ 70,916	\$ 69,589	\$ 84,047	\$ 17,100	\$ (167,495)	\$ 74,157
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	\$ 386	\$ 1,835	\$ 30	\$ 226	\$ —	\$ 2,477
Other current liabilities - affiliates	20,329	14,247	5,744	1,096	(41,416)	—
All other current liabilities	520	323	1,507	300	(27)	2,623
Long-term debt	13,239	15,134	3,000	542	—	31,915
Notes payable to affiliates	1,693	448	20,517	355	(23,013)	—
Deferred income taxes	—	—	625	1,013	(1,638)	—
Other long-term liabilities and deferred credits	1,007	28	1,203	388	(373)	2,253
Total liabilities	37,174	32,015	32,626	3,920	(66,467)	39,268
Redeemable noncontrolling interest	—	—	803	—	—	803
Stockholders' equity						
Total KMI equity	33,742	37,574	50,618	13,180	(101,372)	33,742
Noncontrolling interests	—	—	—	—	344	344
Total stockholders' equity	33,742	37,574	50,618	13,180	(101,028)	34,086
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	\$ 70,916	\$ 69,589	\$ 84,047	\$ 17,100	\$ (167,495)	\$ 74,157

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

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
ASSETS						
Cash and cash equivalents	\$ 8	\$ —	\$ —	\$ 3,277	\$ (5)	\$ 3,280
Other current assets - affiliates	4,465	4,788	23,851	1,031	(34,135)	—
All other current assets	171	17	2,056	212	(14)	2,442
Property, plant and equipment, net	231	—	30,750	6,916	—	37,897
Investments	664	—	6,718	99	—	7,481
Investments in subsidiaries	42,096	40,049	6,077	4,324	(92,546)	—
Goodwill	13,789	22	5,166	2,988	—	21,965
Notes receivable from affiliates	945	20,345	247	1,043	(22,580)	—
Deferred income taxes	3,137	—	—	—	(1,571)	1,566
Other non-current assets	233	105	3,823	74	—	4,235
Total assets	\$ 65,739	\$ 65,326	\$ 78,688	\$ 19,964	\$ (150,851)	\$ 78,866
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	\$ 1,933	\$ 1,300	\$ 30	\$ 125	\$ —	\$ 3,388
Other current liabilities - affiliates	14,189	14,087	4,898	961	(34,135)	—
All other current liabilities	486	354	1,838	1,510	(19)	4,169
Long-term debt	13,474	16,799	3,020	643	—	33,936
Notes payable to affiliates	1,234	448	20,543	355	(22,580)	—
Deferred income taxes	—	—	503	1,068	(1,571)	—
Other long-term liabilities and deferred credits	745	59	944	428	—	2,176
Total liabilities	32,061	33,047	31,776	5,090	(58,305)	43,669
Redeemable noncontrolling interest	—	—	666	—	—	666
Stockholders' equity						
Total KMI equity	33,678	32,279	46,246	14,874	(93,399)	33,678
Noncontrolling interests	—	—	—	—	853	853
Total stockholders' equity	33,678	32,279	46,246	14,874	(92,546)	34,531
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	\$ 65,739	\$ 65,326	\$ 78,688	\$ 19,964	\$ (150,851)	\$ 78,866

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

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	\$ (2,894)	\$ 4,305	\$ 14,102	\$ 575	\$ (11,340)	\$ 4,748
Cash flows from investing activities						
Proceeds from the KML and U.S. Cochran Sale, net of cash disposed	—	—	1,527	—	—	1,527
Proceeds from the TMPL Sale, net of cash disposed and working capital adjustments	—	—	—	(28)	—	(28)
Acquisitions of assets and investments	—	—	(79)	—	—	(79)
Capital expenditures	(22)	—	(1,816)	(432)	—	(2,270)
Sales of property, plant and equipment, investments and other net assets, net of removal costs	9	—	142	(41)	—	110
Contributions to investments	(151)	—	(1,145)	(3)	—	(1,299)
Distributions from equity investments in excess of cumulative earnings	1,315	—	323	—	(1,305)	333
Funding to affiliates	(5,337)	(250)	(11,116)	(895)	17,598	—
Loans to related parties	—	—	(31)	—	—	(31)
Other, net	—	—	23	—	—	23
Net cash used in investing activities	(4,186)	(250)	(12,172)	(1,399)	16,293	(1,714)
Cash flows from financing activities						
Issuances of debt	7,927	—	—	109	—	8,036
Payments of debt	(9,823)	(1,300)	(10)	(91)	—	(11,224)
Debt issue costs	(9)	—	—	(1)	—	(10)
Cash dividends - common shares	(2,163)	—	—	—	—	(2,163)
Repurchases of common shares	(2)	—	—	—	—	(2)
Funding from affiliates	11,172	2,190	3,567	669	(17,598)	—
Contributions from investment partner	—	—	148	—	—	148
Contributions from parents	—	—	3	—	(3)	—
Contributions from noncontrolling interests	—	—	—	—	3	3
Distributions to investment partner	—	—	(11)	—	—	(11)
Distributions to parents	—	(4,945)	(5,627)	(3,012)	13,584	—
Distribution to noncontrolling interests - KML distribution of the TMPL Sale proceeds	—	—	—	—	(879)	(879)
Distributions to noncontrolling interests - other	—	—	—	—	(55)	(55)
Other, net	(28)	—	—	—	—	(28)
Net cash provided by (used in) financing activities	7,074	(4,055)	(1,930)	(2,326)	(4,948)	(6,185)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	29	—	29
Net decrease in Cash, Cash Equivalents and Restricted Deposits	(6)	—	—	(3,121)	5	(3,122)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	8	—	—	3,328	(5)	3,331
Cash, Cash Equivalents, and Restricted Deposits, end of period	\$ 2	\$ —	\$ —	\$ 207	\$ —	\$ 209

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2018
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	\$ (2,758)	\$ 3,879	\$ 11,129	\$ 1,117	\$ (8,324)	\$ 5,043
Cash flows from investing activities						
Proceeds from the TMPL Sale, net of cash disposed and working capital adjustments	—	—	—	2,998	—	2,998
Acquisitions of investments	—	—	(39)	—	—	(39)
Capital expenditures	(24)	—	(1,995)	(885)	—	(2,904)
Sales of property, plant and equipment, investments and other net assets, net of removal costs	9	—	90	5	—	104
Contributions to investments	(12)	—	(413)	(8)	—	(433)
Distributions from equity investments in excess of cumulative earnings	2,342	—	234	1	(2,340)	237
Funding to affiliates	(6,521)	(26)	(7,419)	(1,003)	14,969	—
Loans to related party	—	—	(31)	—	—	(31)
Net cash (used in) provided by investing activities	(4,206)	(26)	(9,573)	1,108	12,629	(68)
Cash flows from financing activities						
Issuances of debt	14,143	—	—	608	—	14,751
Payments of debt	(12,640)	(975)	(784)	(192)	—	(14,591)
Debt issue costs	(35)	—	—	(7)	—	(42)
Cash dividends - common shares	(1,618)	—	—	—	—	(1,618)
Cash dividends - preferred shares	(156)	—	—	—	—	(156)
Repurchases of common shares	(273)	—	—	—	—	(273)
Funding from affiliates	7,560	2,028	4,542	839	(14,969)	—
Contributions from investment partner	—	—	181	—	—	181
Contributions from parents	—	—	19	—	(19)	—
Contributions from noncontrolling interests	—	—	—	—	19	19
Distributions to parents	—	(4,907)	(5,514)	(317)	10,738	—
Distributions to noncontrolling interests	—	—	—	—	(78)	(78)
Other, net	(12)	—	—	(5)	—	(17)
Net cash provided by (used in) financing activities	6,969	(3,854)	(1,556)	926	(4,309)	(1,824)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	(146)	—	(146)
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	5	(1)	—	3,005	(4)	3,005
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	3	1	—	323	(1)	326
Cash, Cash Equivalents, and Restricted Deposits, end of period	\$ 8	\$ —	\$ —	\$ 3,328	\$ (5)	\$ 3,331

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2017
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non- Guarantors	Consolidating Adjustments	Consolidated KMI
Net cash (used in) provided by operating activities	\$ (3,184)	\$ 3,911	\$ 11,523	\$ 1,121	\$ (8,770)	\$ 4,601
Cash flows from investing activities						
Acquisitions of investments	—	—	(4)	—	—	(4)
Capital expenditures	(23)	—	(2,390)	(775)	—	(3,188)
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	16	—	94	8	—	118
Contributions to investments	(237)	—	(435)	(12)	—	(684)
Distributions from equity investments in excess of cumulative earnings	2,297	—	326	—	(2,249)	374
Funding (to) from affiliates	(4,419)	779	(7,040)	(1,028)	11,708	—
Loans to related party	(23)	—	—	—	—	(23)
Other, net	—	1	4	(1)	—	4
Net cash (used in) provided by investing activities	(2,389)	780	(9,445)	(1,808)	9,459	(3,403)
Cash flows from financing activities						
Issuances of debt	8,609	—	—	259	—	8,868
Payments of debt	(9,288)	(600)	(897)	(279)	—	(11,064)
Debt issue costs	(12)	—	—	(58)	—	(70)
Cash dividends - common shares	(1,120)	—	—	—	—	(1,120)
Cash dividends - preferred shares	(156)	—	—	—	—	(156)
Repurchases of common shares	(250)	—	—	—	—	(250)
Funding from (to) affiliates	7,327	776	3,797	(192)	(11,708)	—
Contributions from investment partner	—	—	485	—	—	485
Contributions from parents, including net proceeds from KML IPO and preferred share issuance	—	—	—	1,673	(1,673)	—
Contributions from noncontrolling interests - net proceeds from KML IPO	4	—	—	—	1,241	1,245
Contributions from noncontrolling interests - net proceeds from KML preferred share issuances	—	—	—	—	420	420
Contributions from noncontrolling interests - other	—	—	—	—	12	12
Distributions to parents	—	(4,902)	(5,472)	(687)	11,061	—
Distributions to noncontrolling interests	—	—	—	—	(42)	(42)
Other, net	(9)	—	—	—	—	(9)
Net cash provided by (used in) financing activities	5,105	(4,726)	(2,087)	716	(689)	(1,681)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	22	—	22
Net (decrease) increase in Cash, Cash Equivalents and Restricted Deposits	(468)	(35)	(9)	51	—	(461)
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	471	36	9	272	(1)	787
Cash, Cash Equivalents, and Restricted Deposits, end of period	\$ 3	\$ 1	\$ —	\$ 323	\$ (1)	\$ 326

Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2019				
Revenues	\$ 3,429	\$ 3,214	\$ 3,214	\$ 3,352
Operating Income	1,018	973	951	1,931
Net Income	567	528	517	627
Net Income Attributable to Kinder Morgan, Inc. and Common Stockholders	556	518	506	610
Basic and Diluted Earnings Per Common Share	0.24	0.23	0.22	0.27
2018				
Revenues	\$ 3,418	\$ 3,428	\$ 3,517	\$ 3,781
Operating Income	949	272	1,515	1,058
Net Income (Loss)	542	(130)	1,005	502
Net Income (Loss) Attributable to Kinder Morgan, Inc.	524	(141)	732	494
Net Income (Loss) Available to Common Stockholders	485	(180)	693	483
Basic and Diluted Earnings (Loss) Per Common Share	0.22	(0.08)	0.31	0.21

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 11, 2020

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
<u>/s/ DAVID P. MICHELS</u> David P. Michels	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 11, 2020
<u>/s/ STEVEN J. KEAN</u> Steven J. Kean	Chief Executive Officer (principal executive officer); Director	February 11, 2020
<u>/s/ RICHARD D. KINDER</u> Richard D. Kinder	Executive Chairman	February 11, 2020
<u>/s/ KIMBERLY A. DANG</u> Kimberly A. Dang	President; Director	February 11, 2020
<u>/s/ TED A. GARDNER</u> Ted A. Gardner	Director	February 11, 2020
<u>/s/ ANTHONY W. HALL, JR.</u> Anthony W. Hall, Jr.	Director	February 11, 2020
<u>/s/ GARY L. HULTQUIST</u> Gary L. Hultquist	Director	February 11, 2020
<u>/s/ RONALD L. KUEHN, JR.</u> Ronald L. Kuehn, Jr.	Director	February 11, 2020
<u>/s/ DEBORAH A. MACDONALD</u> Deborah A. Macdonald	Director	February 11, 2020
<u>/s/ MICHAEL C. MORGAN</u> Michael C. Morgan	Director	February 11, 2020
<u>/s/ ARTHUR C. REICHSTETTER</u> Arthur C. Reichstetter	Director	February 11, 2020
<u>/s/ FAYEZ SAROFIM</u> Fayez Sarofim	Director	February 11, 2020
<u>/s/ C. PARK SHAPER</u> C. Park Shaper	Director	February 11, 2020
<u>/s/ WILLIAM A. SMITH</u> William A. Smith	Director	February 11, 2020
<u>/s/ JOEL V. STAFF</u> Joel V. Staff	Director	February 11, 2020
<u>/s/ ROBERT F. VAGT</u> Robert F. Vagt	Director	February 11, 2020
<u>/s/ PERRY M. WAUGHTAL</u> Perry M. Waughtal	Director	February 11, 2020