KINDER MORGAN, INC.
Form 10-K
February 08, 2019
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2018
or

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

For the transition period from _____to_____
Commission file number: 001-35081
Kinder Morgan, Inc.
(Exact name of registrant as specified in its charter)

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

1001 Louisiana Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices) (zip code)

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

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

Title of each class	Name of each exchange on which registered
Class P Common Stock	New York Stock Exchange
1.500% Senior Notes due 2022	New York Stock Exchange
2.250% Senior Notes due 2027	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 of 1933. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes o No þ

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes þ No o

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

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 (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o Emerging growth company o

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. o

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 o No þ

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 29, 2018 was approximately $33,499,494,320. As of February 7, 2019, the registrant had 2,263,656,419 Class P shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant’s definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019, are incorporated into PART III, as specifically set forth in PART III.

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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY
Company Abbreviations

Calnev	= Calnev Pipe Line LLC	KMLP	= Kinder Morgan Louisiana Pipeline LLC
CIG	= Colorado Interstate Gas Company, L.L.C.	KMP	= Kinder Morgan Energy Partners, L.P. and its majority-owned and controlled subsidiaries
CPGPL	= Cheyenne Plains Gas Pipeline Company, L.L.C.		
EagleHawk	= EagleHawk Field Services LLC	KMTP	= Kinder Morgan Texas Pipeline LLC
Elba Express	= Elba Express Company, L.L.C.	MEP	= Midcontinent Express Pipeline LLC
ELC	= Elba Liquefaction Company, L.L.C.	NGPL	= Natural Gas Pipeline Company of America LLC
EPB	= El Paso Pipeline Partners, L.P. and its majority-owned and controlled subsidiaries	Ruby	= Ruby Pipeline Holding 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
KMEP	= Kinder Morgan Energy Partners, L.P.	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.

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	IPO	= Initial Public Offering
		LIBOR	= London Interbank Offered Rate
/d	= per day	LLC	= limited liability company
AFUDC	= allowance for funds used during construction	LNG	= liquefied natural gas
BBtu	= billion British Thermal Units	MBbl	= thousand barrels
Bcf	= billion cubic feet	MDth	= thousand dekatherms
CERCLA	= Comprehensive Environmental Response, Compensation and Liability Act	MLP	= master limited partnership
		MMBbl	= million barrels
C$	= Canadian dollars	MMcf	= million cubic feet
CO_2	= carbon dioxide or our CO_2 business segment	NEB	= Canadian National Energy Board
CPUC	= California Public Utilities Commission	NGL	= natural gas liquids
DCF	= distributable cash flow	NYMEX	= New York Mercantile Exchange
DD&A	= depreciation, depletion and amortization	NYSE	= New York Stock Exchange
Dth	= dekatherms	OTC	= over-the-counter
EBDA	= earnings before 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	U.S.	=	United States of America
FASB	=	Financial Accounting Standards Board	SEC	=	United States Securities and Exchange Commission
FERC	=	Federal Energy Regulatory Commission			
GAAP	=	United States Generally Accepted Accounting Principles	TBtu	=	trillion British Thermal Units
			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,” 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 NGL, refined petroleum products, oil, CO_2, natural gas, electricity, coal, 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;

- changes in our tariff rates required by the FERC, the CPUC, Canada’s NEB or another regulatory agency;

- 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;

- 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;

- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves;

- issues, delays or stoppage associated with new construction or expansion projects;

- regulatory, environmental, political, grass roots opposition, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget or at all;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts at economically attractive rates;
- the ability of our customers and other counterparties to perform under their contracts with us;

- competition from other pipelines, terminals or other forms of transportation;
- 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;
- foreign exchange fluctuations;
- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and work-overs, and in drilling new wells; and
- unfavorable results of litigation and the outcome of contingencies referred to in Note 18 "Litigation, Environmental and Other Contingencies" 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—–(a) General Development of Business—2019 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 84,000 miles of pipelines and 153 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals transload and store liquid commodities including petroleum products, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores. Our common stock trades on the NYSE under the symbol "KMI."

(a) 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 audited 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 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
Divestitures			
TMPL(a)	Sold interests in TMPL, TMEP, Puget Sound system and Kinder Morgan Canada Inc. to the Government of Canada.	Completed in August 2018.	n/a
Placed in service or acquisitions			
TGP Broad Run Expansion	Second of two projects to create a total of 790,000 Dth/d of incremental firm transportation capacity from the southwest Marcellus and Utica supply basins to delivery points in Mississippi and Louisiana. Subscribed under long-term firm transportation contracts.	Broad Run Expansion (200,000 Dth/d) was placed in service October 2018. Broad Run Flexibility facilities (590,000 Dth/d) were placed in service November 2015.	$463 million
KM Base Line Terminal Development(b)	A 12 tank, 4.8 MMBbl, new-build merchant crude oil storage facility in Edmonton, Alberta. Developed as part of a 50-50 joint venture with Keyera Corp. Capital figure includes costs associated with the construction of a pipeline segment funded solely by Kinder Morgan. Subscribed under long-term contracts with an average initial term of 7.5 years.	First 6 tanks placed in service in first quarter 2018 with balance placed in service in the third and fourth quarters of 2018.	C$357 million

Elba Express and SNG Expansion	Expansion project that provides 854,000 Dth/d of incremental natural gas transportation service supporting the needs of customers in Georgia, South Carolina and northern Florida, and also serving ELC. Supported by long-term firm transportation contracts.	Initial service began in December 2016 and as of December 31, 2017, more than 70% of capacity had been placed in service. The final portion was placed in service November 2018.	$284 million

Asset or project	Description	Activity	Approx. Capital Scope
Utopia Pipeline	New 270 mile pipeline, supported by long-term transportation contracts, to transport ethane and ethane-propane mixtures from the prolific Utica Shale, with a design capacity of 50 MBbl/d, expandable to more than 75 MBbl/d. We own a 50% interest in and operate Utopia Holding L.L.C. Riverstone Investment Group LLC owns the remaining 50% interest.	Placed in service January 2018.	$275 million
TGP Southwest Louisiana Supply	Expansion project to provide 900,000 Dth/d of incremental firm transportation capacity from multiple supply basins to the Cameron LNG export facility in Cameron Parish, Louisiana. Subscribed under long-term firm transportation contracts.	Placed in service March 2018.	$175 million
KMLP Sabine Pass Expansion	Expansion project to provide 600,000 Dth/d of incremental firm transportation capacity from various receipt points to Cheniere's Sabine Pass Liquefaction Terminal in Cameron Parish, Louisiana. Subscribed under long-term firm transportation contracts.	Placed in service December 2018.	$133 million
SNG Fairburn Expansion	Expansion project in Georgia to provide 370,000 Dth/d of incremental long-term firm transportation capacity into the Southeast market, and includes the construction of a new compressor station, 6.5 miles of new pipeline and new meter stations.	Placed in service December 2018.	$122 million
TGP Lone Star	Expansion project to provide 300,000 Dth/d of incremental firm transportation capacity from Mississippi receipt points to Cheniere's Corpus Christi LNG export facility in Jackson County, Texas. Subscribed under long-term firm transportation contracts.	Placed in service December 2018.	$106 million
NGPL Gulf Coast Southbound Expansion	Expansion project to provide 460,000 Dth/d of incremental firm transportation capacity from various interstate pipeline interconnects in Illinois, Arkansas and Texas, to points south on NGPL's pipeline system to serve growing demand in the Gulf Coast area. Subscribed under long-term firm transportation contracts.	Partially in service April 2017 (75,000 Dth/d). Remaining (385,000 Dth/d) placed in service October 2018.	$88 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 million tonnes per year of LNG, equivalent to approximately 357,000 Dth/d of natural gas. Supported by a long-term firm contract with Shell.	First of 10 liquefaction units expected to be placed in service at the end of first quarter 2019 with the remaining 9 units to come online throughout 2019.	$1.2 billion
Permian Highway Pipeline Project (PHP Project)(c)	Joint venture pipeline project (KMTP 50% and BCP PHP, LLC (BCP) 50% 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	Expected in-service date fourth quarter 2020, pending regulatory approvals.	$572 million

	Waha, Texas area to the U.S. Gulf Coast and Mexico markets. Subscribed under long-term firm transportation contracts.		
Gulf Coast Express Pipeline Project (GCX Project)	Joint venture pipeline project (KMTP 35%, DCP Midstream, LP 25%, an affiliate of Targa Resources Corp. 25% and Altus Midstream Company 15% ownership interest) to provide up to 1.98 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 with the remaining 40 miles to be placed in-service in April 2019. Expected full in-service date of the project is October 2019.	$637 million
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, that will provide service to the Freeport LNG export facility and other domestic markets.	Phase 1 was placed in service in September 2016. Phase 2 is expected to be placed in service by second quarter 2020.	$298 million

Asset or project	Description	Activity	Approx. Capital Scope
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 placed in service October 2014, phase 2 expected to be in service third quarter 2020.	$138 million
NGPL Gulf Coast Southbound Expansion (second phase)	Expansion project to increase southbound capacity on NGPL's Gulf Coast System to serve Corpus Christi Liquefaction. Subscribed under a long-term firm transportaton contract.	Expected in-service date June 2021, pending regulatory approvals.	$114 million

n/a - not applicable

(a) These assets were included in KML and were partially owned by KML's Restricted Voting Stockholders.

(b) These assets are included in KML and are partially owned by KML's Restricted Voting Stockholders.

(c) An affiliate of an anchor shipper exercised its option in January 2019 to acquire 20% equity interest in the project, bringing KMTP's and BCP's ownership interest to 40% each. Altus Midstream Company (Altus Midstream) (a gas gathering, processing and transportation company formed by shipper Apache Corporation) has an option to acquire an equity interest in the project from the initial partners by September 2019. If Altus Midstream exercises its option, KMTP, BCP and Altus Midstream will each hold a 26.67% ownership interest in the project. Our share of capital scope is adjusted to reflect the potential exercise of Altus Midstream's option.

Financings

On January 3, 2019, KML distributed to us our approximately 70% portion of the proceeds from the TMPL Sale of approximately $1.9 billion (after Canadian tax) which we used to repay our outstanding balance of commercial paper borrowings, and then in February 2019, to repay $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes.

In December 2018 and January 2019, we repurchased approximately 1.5 million and 0.1 million, respectively, of our Class P shares for approximately $23 million and $2 million, respectively, at an average price of $15.54 per share, as part of our $2 billion common share buy-back program approved by our board of directors in December 2017.

On November 16, 2018, we entered into (i) a new five-year $4.0 billion revolving credit agreement and (ii) a new 364-day $500 million revolving credit agreement with a syndicate of lenders and replaced the prior KMI credit agreement.

2019 Outlook

We expect to declare dividends of $1.00 per share for 2019, a 25% increase from the 2018 declared dividends of $0.80 per share, and generate approximately $5.0 billion of DCF in 2019. We also expect to invest $3.1 billion in expansion projects and contributions to joint ventures during 2019. Our discretionary spending will be primarily funded with excess, internally generated cash flow, with no need to access equity markets during 2019.

We are unable to provide budgeted net income attributable to common stockholders (the GAAP financial measure most directly comparable to DCF) due to the impracticality of predicting certain amounts required by GAAP, such as unrealized gains and losses on derivatives marked to market, and potential changes in estimates for certain contingent liabilities. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures."

Our expectations for 2019 assume average annual prices for WTI crude oil and Henry Hub natural gas of $60.00 per barrel and $3.15 per MMBtu, respectively, consistent with forward pricing during our 2019 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 CO_2 segment, in which we hedge the majority of the next 12 months of oil and NGL production to minimize this sensitivity. For 2019, we estimate that every $1 change in the average WTI crude oil price per barrel from our budget of $60.00 per barrel would impact our budgeted DCF by approximately $8 million and each $0.10 per MMBtu change in the average price of natural gas from our budget of $3.15 per MMBtu would impact budgeted DCF by approximately $1 million.

In addition, our expectations for 2019 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 for more information. Furthermore, we plan to provide updates to our 2019 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

(b) Financial Information about Segments

For financial information on our reportable business segments, see Note 17 "Reportable Segments" to our consolidated financial statements.

(c) 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;
- leverage economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow; and
- maintain a strong balance sheet 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, 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
Our business segments and their primary activities and sources of revenues are as follows:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;
- Products Pipelines—the ownership and operation of refined petroleum products, NGL and 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 that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;
- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gas 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.

Natural Gas Pipelines

Our Natural Gas Pipelines business segment includes interstate and intrastate pipelines and our LNG terminals, 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 46,000 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, the Midwest, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG terminals 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, 2018. The Design Capacity represents transmission, gathering 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
Natural Gas Pipelines				
TGP	11,775	12.10	76	Marcellus, Utica, Gulf Coast, Haynesville, and Eagle Ford shale supply basins; Northeast, Southeast U.S., Gulf Coast and U.S.-Mexico border
EPNG/Mojave pipeline system	10,660	5.65	44	Northern New Mexico, Texas, Oklahoma, to California, connects to San Juan, Permian and Anadarko basins
NGPL (50%)	9,100	7.60	288	Chicago and other Midwest markets and all central U.S. supply basins; north to south for LNG and to U.S.-Mexico border
SNG (50%)	6,950	4.32	66	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee; basins in Texas, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus) (50%)	5,350	3.90	—	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
CIG	4,280	5.15	38	Colorado and Wyoming; Rocky Mountains and the Anadarko Basin
WIC	850	3.83	—	Wyoming, Colorado and Utah; Overthrust, Piceance, Uinta, Powder River and Green River Basins
Ruby (50%)(a)	680	1.53	—	Wyoming to Oregon with interconnects supplying California and the Pacific Northwest; Rocky Mountain basins
MEP (50%)	510	1.80	—	Oklahoma and north Texas supply basins to interconnects with deliveries to interconnects with Transco, Columbia Gulf and various other pipelines
CPGPL	410	1.20	—	Colorado and Kansas, natural gas basins in the Central Rocky Mountain area
TransColorado Gas	310	0.80	—	Colorado and New Mexico; connects to San Juan, Paradox and Piceance basins

WYCO (50%)	224	1.20	7	Northeast Colorado; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCo’s pipeline system
Elba Express	200	1.06	—	Georgia; connects to SNG (Georgia), Transco (Georgia/South Carolina), SLNG (Georgia) and Dominion Energy Carolina Gas Transmission (Georgia)
FEP (50%)	185	2.00	—	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission and ANR Pipeline Company
KMLP	135	2.95	—	Columbia Gulf, ANR Pipeline Company and various other pipeline interconnects; Cheniere Sabine Pass LNG and industrial markets
Sierrita Gas Pipeline LLC (35%)	60	0.20	—	Near Tucson, Arizona, to the U.S.-Mexico border near Sasabe, Arizona; connects to EPNG and via an international border crossing with a third-party natural gas pipeline in Mexico
Young Gas Storage (48%)	17	—	5.8	Morgan County, Colorado, capacity is committed to CIG and Colorado Springs Utilities
Keystone Gas Storage	15	—	6.4	Located in the Permian Basin and near the WAHA natural gas trading hub in West Texas

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
Gulf LNG Holdings (50%)	5	1.50	6.6	Near Pascagoula, Mississippi; connects to four interstate pipelines and a natural gas processing plant
Bear Creek Storage (75%)	—	—	59.2	Located in Louisiana; provides storage capacity to SNG and TGP
SLNG	—	1.76	11.5	Georgia; connects to Elba Express, SNG and Dominion Energy Carolina Gas Transmission
ELC (51%)	—	0.35	—	Georgia; expect phased in-service Q1 2019 through Q4 2019
Midstream Natural Gas Assets				
KM Texas and Tejas pipelines	5,640	7.00	134 [0.51]	Texas Gulf Coast
Mier-Monterrey pipeline	90	0.65	—	Starr County, Texas to Monterrey, Mexico; connect to CENEGAS national system and multiple power plants in Monterrey
KM North Texas pipeline	80	0.33	—	Interconnect from NGPL; connects to 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Oklahoma				
Oklahoma System	4,075	0.75	[0.14]	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	1,300	1.93	[1.02]	Eagle Ford shale, Woodbine and Eaglebine formations
Webb/Duval gas gathering system (63%)	145	0.15	—	South Texas
EagleHawk (25%)	530	1.20	—	South Texas, Eagle Ford shale formation
KM Altamont	1,370	0.08	[0.08]	Utah, Uinta Basin
Red Cedar (49%)	900	0.55	—	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union (37%)	310	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
North Texas	550	0.14	[0.10]	North Barnett Shale Combo
Camino Real	70	0.15	—	South Texas, Eagle Ford shale formation
KM Treating	—	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
Hiland - Williston	2,030	0.37	[0.20]	Bakken/Three Forks shale formations (North Dakota/Montana)

Midstream Liquids/Oil/Condensate Pipelines

		(MBbl/d)	(MBbl)	
Liberty Pipeline (50%)	87	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
Camino Real - Condensate(b)	70	110	60	South Texas, Eagle Ford shale formation
Hiland - Williston - Oil(b)	1,587	282	—	Bakken/Three Forks shale formations (North Dakota/Montana)
EagleHawk - Condensate (25%)	400	220	60	South Texas, Eagle Ford shale formation

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(a) We operate Ruby and own the common interest in Ruby. Pembina Pipeline Corporation (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) Effective January 1, 2019, these assets were transferred from the Natural Gas Pipelines business segment to the Products Pipelines business segment.

Competition

The market for supply of natural gas is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve the growing demand for natural gas in each of the markets served by the pipelines in our Natural Gas Pipelines business segment. Our operations compete with interstate and intrastate pipelines, and their shippers, 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 and flexibility and reliability of service. From time to time, other projects are proposed that would compete with us. We do not know whether or when any such projects would be built, or the extent of their impact on our operations or profitability.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including electricity, coal, propane, fuel oils and renewables such as wind and solar. Several factors influence the demand for natural gas, including price changes, the availability of natural gas and 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, and NGL pipelines and associated terminals, Southeast terminals, our condensate processing facility and our transmix processing facilities. The following summarizes our significant Products Pipelines business segment assets we own and operate as of December 31, 2018:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity(MMBbl)	Supply and Market Region
Plantation pipeline (51%)	3,182	—	—	Louisiana to Washington D.C.
West Coast Products Pipelines(b)				
Pacific (SFPP)	2,845	13	15.1	Six western states
Calnev	566	2	2.0	Colton, CA to Las Vegas, NV; Mojave region
West Coast Terminals	64	7	10.0	Seattle, Portland, San Francisco and Los Angeles areas, Vancouver Jet Fuel pipeline
Cochin pipeline(c)	1,525	4	1.1	Three provinces in Canada and seven states in the U.S.
Utopia pipeline (50%)(c)	270	—	—	Harrison County, Ohio extending to Windsor, Ontario
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
Double H Pipeline	512	—	—	Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Central Florida pipeline	206	2	2.5	Tampa to Orlando
Double Eagle pipeline (50%)	204	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County

Cypress pipeline (50%)(c)	104	—	—	Mont Belvieu, Texas to Lake Charles, Louisiana
Southeast Terminals(d)	—	32	10.8	From Mississippi through Virginia, including Tennessee
KM Condensate Processing Facility	—	1	2.0	Houston Ship Channel, Galena Park, Texas
Transmix Operations	—	5	0.6	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; St. Louis, Missouri; and Greensboro, North Carolina

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(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

(b) Our West Coast Products Pipelines assets include interstate common carrier pipelines rate-regulated by the FERC, intrastate pipelines in the state of California rate-regulated by the CPUC, and certain non rate-regulated operations and terminal facilities.

(c) Effective January 1, 2019, these assets were transferred from the Products Pipelines business segment to the Natural Gas Pipelines business segment.
(d) Effective January 1, 2019, a small number of terminals were transferred between the Products Pipelines and Terminals business segments.

Competition

Our Products Pipelines' pipeline operations compete against proprietary pipelines owned and operated by major oil companies, other independent products pipelines, trucking and marine transportation firms (for short-haul movements of products) and railcars. Our Products Pipelines' terminal operations compete with proprietary terminals owned and operated by major oil companies and other independent terminal operators, 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, crude oil, 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. and in portions of Canada. 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, 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, 2018:

	Number	Capacity (MMBbl)
Liquids terminals(a)	52	89.6
Bulk terminals	34	—
Jones Act tankers	16	5.3

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(a) Effective January 1, 2019, a small number of terminals were transferred between the Terminals and Products Pipelines business segments.

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.

CO_2

Our CO_2 business segment produces, transports, and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 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.

Sales and Transportation Activities

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin. Our ownership of CO_2 resources as of December 31, 2018 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

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(a) We do not operate this unit.

CO_2 Business Segment Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable for the next several years. 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 CO_2 pipelines are not regulated.

Our ownership of CO_2 and crude oil pipelines as of December 31, 2018 includes:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Transport Capacity (Bcf/d)	Supply and Market Region
CO_2 pipelines			
Cortez pipeline (53%)	569	1.5	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	334	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	457	145,000	West Texas to Western Refining's refinery in El Paso, Texas

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(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 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
Sharon Ridge	14	2,619
Tall Cotton	100	641
MidCross	13	320
Reinecke	70	3,793

Our oil and gas producing activities are not significant, and 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

Operated gas plants in the Permian Basin of West Texas:

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

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2018, 2017 and 2016, 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.

Our Texas Intrastate Natural Gas Pipeline operations (includes the operations of Kinder Morgan Tejas Pipeline LLC, Kinder Morgan Border Pipeline LLC, Kinder Morgan Texas Pipeline LLC, Kinder Morgan North Texas Pipeline LLC and the Mier-Monterrey Mexico pipeline system) buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, the CO_2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from the Natural Gas Pipelines and CO_2 business segments in 2018, 2017 and 2016 accounted for 23%, 22% and 19%, respectively, of our total consolidated revenues. To the extent possible, we attempt to balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are often settled in terms of an index price for both purchases and sales.

Regulation

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation - U.S. Operations

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 carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common 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 Pacific operations’ pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines’ rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 18 “Litigation, Environmental and Other Contingencies” 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.

Common Carrier Pipeline Rate Regulation - Canadian Operations

The Canadian portion of our condensate Cochin pipeline system is under the regulatory jurisdiction of the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service.

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-1980's, the FERC initiated a number of regulatory changes intended 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. Among the most important of these changes were:

- Order No. 436 (1985) which required open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;
- Order Nos. 587, et seq., Order No. 809 (1996-2015) which adopt regulations to standardize the business practices and communication methodologies of interstate natural gas pipelines to create a more integrated and efficient pipeline grid and wherein the FERC has incorporated by reference in its regulations standards for interstate natural gas pipeline business practices and electronic communications that were developed and adopted by the North American Energy Standards Board (NAESB). Interstate natural gas pipelines are required to incorporate by reference or verbatim in their respective tariffs the applicable version of the NAESB standards;
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies. Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for transportation services and storage services for natural gas);
- Order No. 637 (2000) which revised, among other things, FERC regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties in order to improve the competitiveness and efficiency of the interstate pipeline grid; and
- Order No. 717 (2008) amending the Standards of Conduct for Transmission Providers (the Standards of Conduct or the Standards) to make them clearer and to refocus the marketing affiliate rules on the areas where there is the greatest potential for abuse.

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.

CPUC Rate Regulation

The intrastate common carrier operations of our Pacific 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 Pacific 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, as is more fully described in Note 18 “Litigation, Environmental and Other Contingencies” to our consolidated financial statements.

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, where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with pipeline Integrity Management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional integrity threats and changes to the amount of pipe determined to be located in HCAs 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. These tests could result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to continue the safe and reliable operation of our pipelines.

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, Provincial and Local Regulation

Certain of our activities are subject to various state or provincial 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 Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and crewed by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign-flagged vessels.

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

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

Environmental Matters

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the U.S. and Canada. 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 or provincial laws, including 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, state and provincial environmental laws could require significant capital expenditures at our facilities.

Environmental and human health and safety laws and regulations are subject to change. The clear 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 accrue 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 $271 million as of December 31, 2018. Our aggregate reserve estimate ranges in value from approximately $271 million to approximately $448 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, Environmental and Other Contingencies” 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 and Canadian federal and provincial statutes. From time to time, the EPA, as well as other U.S. federal and state regulators and Canadian federal and provincial 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 and Canadian statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of 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 pollutants into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal, state or Canadian 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 and Canadian 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

Studies have suggested that emissions of certain gases, commonly referred to as GHGs, may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and CO_2, 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 CO_2 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 CO_2 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 more strict 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 CO_2, 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 of 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 entities in the 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 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 CO_2 business segment. However, these potential positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, GHG regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

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

Other

Employees

We employed 11,012 full-time personnel at December 31, 2018, including approximately 936 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2019 and 2022. 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, provincial 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.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 17 "Reportable Segments" to our consolidated financial statements.

(e) 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 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, CO_2, coal, 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, provincial, state and municipal governments and oil and gas industry participants. In addition, emerging technologies and public opinion have resulted in increasing demand for energy efficiency, including 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, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, 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 and 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 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 related 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.

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, 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 CO_2 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 CO_2 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 2019, we estimate that every $1 change in the average WTI crude oil price per barrel would impact our DCF by approximately $8 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 WTI crude oil price per barrel would impact DCF by approximately $3 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 CO_2 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, the coal 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. 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 CO_2 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. For example, PG&E, a customer of Ruby, filed for Chapter 11 bankruptcy protection in January 2019. See Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—General—Investment in Ruby.” 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. 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 CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

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. 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 and natural gas.

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 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 price 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. 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.

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 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 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, 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—(c) 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, CO_2 or crude oil—and the laws of the particular state. In any case, we must compensate landowners for the use of their property, and in eminent domain actions, such compensation may be determined by a court. If we are unable to obtain rights-of-way on acceptable terms, our ability to complete construction projects on time, on budget, or at all, could be adversely affected. In addition, we are subject to the possibility of increased costs under our 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.

The increased financial reporting and other obligations of management resulting from KML's obligations as a public company may divert management's attention away from other business operations.

KML, in which we own an approximate 70% interest, completed its IPO in Canada in May of 2017 and in 2018, completed the sale of its interest in the TMPL as described under Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project." Certain of our officers and directors also serve as officers and directors of KML, and we provide financial reporting support and other services as requested by KML and its controlled affiliates pursuant to a Services Agreement. The increased obligations associated with providing support to KML as a public company may divert our management's attention from other business concerns and may adversely affect our business, financial condition and results of operations. We are subject to financial reporting and other obligations that place significant demands on our management, administrative, operational, legal, internal audit and accounting resources. The demands on our personnel related to KML's obligations as a public company will be intensified as a result of the management and personnel departures and related transition following the sale of our interest in the TMPL.

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 Terminals business segment is subject to U.S. dollar/Canadian dollar exchange rate fluctuations as a result of operations in Canada.

We are a U.S. dollar reporting company. As a result of the operations of our Terminals business segment in Canada, a portion of our consolidated assets, liabilities, revenues, cash flows and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between U.S. and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our stockholders' equity under applicable accounting rules.

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, 2018, we had approximately $36.6 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 earnings before interest, taxes, depreciation and amortization, or 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. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

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

As of December 31, 2018, approximately $11.4 billion of our approximately $36.6 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. 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.

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

Our and our customer’s access to capital could be affected by evolving financial institutions’ 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 energy-related activities. Ultimately, this could make it more difficult for our customers to secure funding for exploration and production activities, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

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, the CPUC, or the NEB may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, the NEB, 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, the CPUC, or the NEB 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, Environmental and Other Contingencies" to our consolidated financial statements, to the rates we charge on our pipelines. In addition, following the 2017 Tax Reform, which reduced the corporate tax rate from 35% to 21%, the FERC initiated the Form 501-G process to review the estimated impact of the 2017 Tax Reform on interstate pipelines with respect to tax recovery in existing jurisdictional rates. See Note 18 "Litigation, Environmental and Other Contingencies—FERC Proceedings" to our consolidated financial statements. 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, provincial 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, provincial 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) the acquisition of other 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, such as the 2017 Tax Reform and the resulting Form 501-G process initiated by FERC, 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—(c) 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, provincial 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 or provincial 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 the regulatory schemes of the various Canadian provinces, such as British Columbia's Environmental Management Act, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. 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, state and provincial 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—(c) 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, state and provincial 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 change and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of GHGs such as methane and CO_2, including the EPA programs to control GHG emissions and state actions to develop statewide or regional programs. Existing EPA regulations require us to report GHG emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO_2 (for example, from our McElmo Dome CO_2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further 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—(c) 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, provincial 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, Environmental and Other Contingencies” 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, 2018.

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, 2019, we had 11,434 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

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

Our Purchases of Our Class P Shares

Period	Total number of securities purchased(a)	Average price paid per security	Total number of securities purchased as part of publicly announced plans(a)	Maximum number (or approximate dollar value) of securities that may yet be purchased under the plans or programs
October 1 to October 31, 2018	—	$ —	—	$ 1,500,000,715
November 1 to November 30, 2018	—	$ —	—	$ 1,500,000,715
December 1 to December 31, 2018(b)	1,473,120	$ 15.56	1,473,120	$ 1,477,062,687
Total	1,473,120	$ 15.56	1,473,120	$ 1,477,062,687

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(a) On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. After repurchase, the shares are cancelled and no longer outstanding.

(b) Excludes repurchases made in December 2018 of 0.1 million shares for approximately $2 million which settled on January 2, 2019.

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,				
	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Income and Cash Flow Data:					
Revenues	$14,144	$13,705	$13,058	$14,403	$16,226
Operating income	3,794	3,529	3,538	2,378	4,387
Earnings from equity investments	887	578	497	414	406
Net income	1,919	223	721	208	2,443
Net income attributable to Kinder Morgan, Inc.	1,609	183	708	253	1,026
Net income available to common stockholders	1,481	27	552	227	1,026
Class P Shares					
Basic and Diluted Earnings Per Common Share From Continuing Operations	$0.66	$0.01	$0.25	$0.10	$0.89
Basic Weighted Average Common Shares Outstanding	2,216	2,230	2,230	2,187	1,137
Dividends per common share declared for the period(a)	$0.80	$0.50	$0.50	$1.61	$1.74
Dividends per common share paid in the period(a)	0.725	0.50	0.50	1.93	1.70
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	$37,897	$40,155	$38,705	$40,547	$38,564
Total assets	78,866	79,055	80,305	84,104	83,049
Current portion of debt(b)	3,388	2,828	2,696	821	2,717
Long-term debt(c)	33,205	34,088	36,205	40,732	38,312

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

(b) Using part of our portion of proceeds from the TMPL Sale that KML distributed to us in January 2019, we immediately repaid our outstanding balance of commercial paper of $409 million and then repaid $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes in February 2019.

(c) 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—(c) Narrative Description of Business—Business Strategy;" (ii) a description of developments during 2018, found in Items 1 and 2 "Business and Properties—(a) General Development of Business—Recent Developments;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

Inasmuch as the discussion below and the other sections to which we have referred you pertain to management's comments on financial resources, capital spending, our business strategy and the outlook for our business, such discussions contain forward-looking statements. These forward-looking statements reflect the expectations, beliefs, plans and objectives of management about future financial performance and assumptions underlying management's judgment concerning the matters discussed, and accordingly, involve estimates, assumptions, judgments and uncertainties. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to any differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in Item 1A "Risk Factors" and at the beginning of this report in "Information Regarding Forward-Looking Statements."

General

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 and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and 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 that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gasoline processing plants in West Texas; 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.

As an energy infrastructure owner and operator in multiple facets of the various U.S. and Canadian 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.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. 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, 2018, the remaining weighted average contract life of our natural gas transportation contracts (including intrastate pipelines' sales portfolio) was approximately six years.

Our midstream assets provide gathering and processing services for natural gas and gathering services for crude oil. 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.

The profitability of our refined petroleum products pipeline transportation and storage 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 approximately 55 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 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.

Our crude and condensate transportation services are primarily provided either pursuant to (i) long-term contracts that normally contain minimum volume commitments or (ii) through terms prescribed by the toll settlements with shippers and approved by regulatory authorities. 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 crude oil and condensate pipelines are affected by the volumes of crude oil 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.

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 four 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. For the most part, we have contracts for this business that 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 factors such as hurricanes and other weather related events 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 tankers in our Terminals business segment. As of December 31, 2018, 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 currently operating pursuant to multi-year fixed price charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2018, had a remaining average contract life of approximately nine years. CO_2 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 2019 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 CO_2 business segment is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, 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 $57.83 per barrel in 2018, $58.40 per barrel in 2017 and $61.52 per barrel in 2016. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $58.63 per barrel in 2018, $49.61 per barrel in 2017 and $41.36 per barrel in 2016.

Also, see Note 16 “Revenue Recognition” to our consolidated financial statements for more information about the types of contracts and revenues recognized for each of our segments.

Investment in Ruby

In January 2019, Pacific Gas and Electric (PG&E) filed for Chapter 11 bankruptcy protection. Our exposure to PG&E is limited to our $750 million equity investment in Ruby and an approximate $55 million note receivable from Ruby, where PG&E is Ruby’s largest customer. PG&E represents approximately $93 million of annual revenues on Ruby, and our partner’s preferred equity interest in Ruby is senior to our interest. Despite the bankruptcy filing, Ruby continues to perform under its existing service contracts with PG&E, and PG&E has provided credit support on its trade payables to Ruby through a prepayment arrangement. While the ultimate outcome of the bankruptcy proceedings remains uncertain, there is the potential for Ruby’s existing contracts with PG&E to be canceled in the bankruptcy process. Any cancellation of these contracts could negatively impact Ruby’s future revenues and require us to evaluate our investment in Ruby for an other than temporary impairment. This could result in a material impairment of our investment in Ruby at the time such events become known.

KML

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 and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business, which were indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for 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 $596 million within “Loss on impairments and divestitures, net” in our accompanying consolidated statement of income during the year ended December 31, 2018, including an incremental working capital adjustment of $26 million accrued as of December 31, 2018.

On January 3, 2019, pursuant to KML’s shareholders’ approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see Note 9 “Debt—Credit Facilities and Restrictive Covenants—KML”). KML’s public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximate 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately 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. To facilitate the return of capital and provide flexibility for KML’s dividends going forward, KML’s shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, which was recorded in the fourth quarter of 2018, along with a “reverse stock split” of KML’s restricted voting shares, and KML’s special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

KML continues to manage a portfolio of strategic infrastructure assets across Western Canada, including (i) the crude terminal facilities, which constitute the largest merchant terminal storage position in the Edmonton market and the largest origination crude by rail loading facility in North America; (ii) the Vancouver Wharves Terminal, the largest mineral concentrate export/import facility on the west coast of North America; (iii) the Jet Fuel pipeline system; and (iv) the Canadian portion of the U.S. and Canadian Cochin pipeline system. These KML assets are part of our Products Pipelines and Terminals business segments.

KML IPO

The interest in the Canadian business operations that we sold to the public on May 30, 2017 in KML's IPO represented an interest in all our operating assets in our Kinder Morgan Canada business segment and our operating Canadian assets in our Terminals and Products Pipelines business segments. These Canadian assets included the TMPL, TMEP and the Puget Sound pipeline system, all of which have been sold in the TMPL Sale, the Jet Fuel pipeline system, the Canadian portion of the Cochin pipeline system, the Vancouver Wharves Terminal and the North 40 Terminal; as well as three jointly controlled investments: the Edmonton Rail Terminal, the Alberta Crude Terminal and the Base Line Terminal.

Subsequent to the IPO, we retained control of KML, and as a result, it remains consolidated in our consolidated financial statements. The public ownership of the KML restricted voting shares is reflected within "Noncontrolling interests" in our consolidated statements of stockholders' equity and consolidated balance sheets. Earnings attributable to the public ownership of KML are presented in "Net income attributable to noncontrolling interests" in our consolidated statements of income for the periods presented after May 30, 2017. KML transacts in and/or uses the Canadian dollar as the functional currency, which affects our segment results due to the variability in U.S. - Canadian dollar exchange rates.

Subsequent to its IPO, KML has obtained a credit facility and completed two preferred share offerings. KML continues to be a self-funding entity and we do not anticipate making contributions to fund its growth or operations.

2017 Tax Reform

While the 2017 Tax Reform will ultimately be moderately positive for us, the reduced corporate income tax rate caused certain of our deferred-tax assets to be revalued at 21% versus 35% at the end of 2017. Although there is no impact to the underlying related deductions, which can continue to be used to offset future taxable income, we took an estimated approximately $1.4 billion non-cash accounting charge in 2017. The positive impacts of the law include the reduced corporate income tax rate and the fact that several of our U.S. business units (essentially all but our interstate natural gas pipelines) will be able to deduct 100% of their capital expenditures through 2022. See Note 5 "Income Taxes" to our consolidated financial statements.

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 to (a) assign purchase price from business combinations, (b) determine possible asset and equity investment impairment charges, and (c) calculate 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) computing 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—(c) Narrative Description of Business—Environmental Matters.” For more information on our environmental disclosures, see Note 18 “Litigation, Environmental and Other Contingencies” 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, 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, Environmental and Other Contingencies” 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 net investments in foreign operations, and to balance our exposure to fixed and variable interest rates, and we believe that these hedges are 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 item being hedged, and any ineffective portion of the hedge gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately.

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 plans based on their overfunded or underfunded status. As of December 31, 2018, our pension plans were underfunded by $702 million, and our other postretirement benefits plans were underfunded by $33 million. Our pension and other postretirement benefit 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 other postretirement benefit 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 other postretirement benefits can be, and often are, revised in the future. 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, 2018, we had deferred net losses of approximately $536 million in pre-tax accumulated other comprehensive loss related to our pension and other postretirement benefits.

The following table shows the impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2018:

	Pension Benefits		Other Postretirement Benefits	
	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)	$ 183	$ (1)	$ 25
Expected return on plan assets	(21)	—	(3)	—
Rate of compensation increase	2	(7)	—	—
Health care cost trends	—	—	3	(16)
One percent decrease in:				
Discount rates	13	(214)	1	(29)
Expected return on plan assets	21	—	3	—
Rate of compensation increase	(2)	7	—	—
Health care cost trends	—	—	(3)	14

(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

Our management evaluates our performance primarily using the measures of Segment EBDA and, as discussed below under "—Non-GAAP Financial Measures," DCF, and Segment EBDA before certain items. 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, interest expense, net, and income taxes. Our general and administrative expenses 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.

In our discussions of the operating results of individual businesses that follow, we generally identify the important fluctuations between periods that are attributable to dispositions and acquisitions separately from those that are attributable to businesses owned in both periods.

Effective January 1, 2019, certain assets were transferred between Natural Gas Pipelines, Products Pipelines and Terminals business segments, which are not reflected in the following business segment Management Discussion and Analysis tables below.

Consolidated Earnings Results

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Segment EBDA(a)			
Natural Gas Pipelines	$3,580	$3,487	$3,211
Products Pipelines	1,173	1,231	1,067
Terminals	1,171	1,224	1,078
CO_2	759	847	827
Kinder Morgan Canada(b)	720	186	181
Total segment EBDA(c)	7,403	6,975	6,364
DD&A	(2,297)	(2,261)	(2,209)
Amortization of excess cost of equity investments	(95)	(61)	(59)
General and administrative and corporate charges(d)	(588)	(660)	(652)
Interest, net(e)	(1,917)	(1,832)	(1,806)
Income before income taxes	2,506	2,161	1,638
Income tax expense(f)	(587)	(1,938)	(917)
Net income	1,919	223	721
Net income attributable to noncontrolling interests	(310)	(40)	(13)
Net income attributable to Kinder Morgan, Inc.	1,609	183	708
Preferred stock dividends	(128)	(156)	(156)
Net income available to common stockholders	$1,481	$27	$552

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

(b) 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 Total Segment EBDA (see "—Non-GAAP Measures" below)

(c)

2018, 2017 and 2016 amounts include net decreases in earnings of $269 million, $384 million and $1,121 million, respectively, related to the combined net effect of the certain items impacting Total Segment EBDA. The extent to which these items affect each of our business segments is discussed below in the footnotes to the tables within “—Segment Earnings Results.”

(d) 2018, 2017 and 2016 amounts include net increases in expense of $24 million and $15 million and a net decrease in expense of $13 million, respectively, related to the combined net effect of the certain items related to general and administrative and corporate charges disclosed below in "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

(e) 2018, 2017 and 2016 amounts include a net increase in expense of $26 million and net decreases in expense of $39 million and $193 million, respectively, related to the combined net effect of the certain items related to interest expense, net disclosed below in "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

(f) 2018, 2017 and 2016 amounts include a net decrease of $58 million and net increases in expense of $1,085 million and $18 million, respectively, related to the combined net effect of the certain items related to income tax expense representing the income tax provision on certain items plus discrete income tax items.

Year Ended December 31, 2018 vs. 2017

The certain item totals reflected in footnotes (c) through (e) to the table above accounted for $41 million of the increase in income before income taxes in 2018 as compared to 2017 (representing the difference between decreases of $319 million and $360 million from certain items in income before income taxes for 2018 and 2017, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining increase of $304 million (12%) from the prior year in income before income taxes is primarily attributable to increased performance from our Natural Gas Pipelines, Products Pipelines, and CO_2 business segments and decreased general and administrative expense partially offset by increased DD&A expense, interest expense, net and lower earnings from our Kinder Morgan Canada business segment as a result of the TMPL Sale and our Terminals business segment.

Year Ended December 31, 2017 vs. 2016

The certain item totals reflected in footnotes (c) through (e) to the table above accounted for $555 million of the increase in income before income taxes in 2017 as compared to 2016 (representing the difference between decreases of $360 million and $915 million from certain items in income before income taxes for 2017 and 2016, respectively). After giving effect to these certain items, which are discussed in more detail in the discussion that follows, the remaining decrease of $32 million (1%) from the prior year in income before income taxes is primarily attributable to decreased performance from our Natural Gas Pipelines business segment, largely associated with our sale of a 50% interest in SNG to The Southern Company (Southern Company) on September 1, 2016, and increased DD&A expense partially offset by decreased general and administrative expense and decreased interest expense.

Non-GAAP Financial Measures

Our non-GAAP performance measures are DCF, both in the aggregate and per share, and Segment EBDA before certain items. Certain items, as used to calculate our non-GAAP 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).

Our non-GAAP performance 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 DCF and Segment EBDA before certain items may differ from similarly titled measures used by others. You should not consider these non-GAAP performance measures in isolation or as substitutes for an analysis of our results as reported under GAAP. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. Management compensates for the limitations of these non-GAAP performance 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.

DCF

DCF is calculated by adjusting net income available to common stockholders before certain items for DD&A, total book and 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 and preferred stock dividends, 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. We believe the GAAP measure most directly comparable to DCF is net income available to common stockholders. A reconciliation of DCF to net income available to common stockholders is provided in the table below. DCF per common share is DCF divided by average outstanding common shares, including restricted stock awards that participate in dividends.

Reconciliation of Net Income Available to Common Stockholders to DCF

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Net Income Available to Common Stockholders	$1,481	$27	$552
Add/(Subtract):			
Certain items before book tax(a)	355	141	915
Noncontrolling interest certain items(b)	240	—	(8)
Book tax certain items(c)	(58)	(77)	18
Impact of 2017 Tax Reform(d)	(36)	1,381	—
Total certain items	501	1,445	925
Net income available to common stockholders before certain items	1,982	1,472	1,477
Add/(Subtract):			
DD&A expense(e)	2,752	2,684	2,617
Total book taxes(f)	710	957	993
Cash taxes(g)	(77)	(72)	(79)
Other items(h)	15	29	43
Sustaining capital expenditures(i)	(652)	(588)	(540)
DCF	$4,730	$4,482	$4,511
Weighted average common shares outstanding for dividends(j)	2,228	2,240	2,238
DCF per common share	$2.12	$2.00	$2.02
Declared dividend per common share	0.80	0.50	0.50

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(a) Consists of certain items summarized in footnotes (c) through (e) to the "—Results of Operations—Consolidated Earnings Results" table included above, and described in more detail below in the footnotes to tables included in "—Segment Earnings Results" and "—General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests."

(b) Represents noncontrolling interests share of certain items. 2018 includes KML shareholders' approximately 30% share of the gain on the TMPL Sale.

(c) Represents income tax provision on certain items plus discrete income tax items.

(d) 2018 amount represents 2017 Tax Reform provisional adjustments including our share of certain equity investees' 2017 Tax Reform provisional adjustments related to our FERC regulated business. 2017 amount includes book tax certain items and $219 million pre-tax certain items related to our FERC regulated business. See Note 5 "Income Taxes" to our consolidated financial statements.

(e) Includes DD&A and amortization of excess cost of equity investments. Also includes our share of certain equity investee's DD&A, net of the noncontrolling interests' portion of KML DD&A and consolidating joint venture partners' share of DD&A of $360 million, $362 million and $349 million in 2018, 2017 and 2016, respectively.

(f) Excludes book tax certain items of $58 million, $(1,085) million and $(18) million for 2018, 2017 and 2016, respectively. 2018, 2017 and 2016 amounts also include $65 million, $104 million and $94 million, respectively, of our share of taxable equity investees' book taxes, net of the noncontrolling interests' portion of KML book taxes.

(g) Includes our share of taxable equity investees' cash taxes of $(68) million, $(69) million and $(76) million in 2018, 2017 and 2016, respectively.

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

(i) Includes our share of (i) certain equity investees'; (ii) KML's; and (iii) certain consolidating joint venture subsidiaries' sustaining capital expenditures of $(105) million, $(107) million and $(90) million in 2018, 2017 and 2016, respectively.

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

Segment EBDA Before Certain Items

Segment EBDA before certain items is used by management in its analysis of segment performance and management of our business. General and administrative expenses generally are not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. We believe Segment EBDA before certain items is a significant performance metric because it provides us and external users of our financial statements additional insight into the ability of our business segments to generate segment cash earnings on an ongoing basis. We believe it is useful to investors because it is a performance 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 Segment EBDA before certain items is Segment EBDA.

In the tables for each of our business segments under "— Segment Earnings Results" below, Segment EBDA before certain items and Revenues before certain items are calculated by adjusting the Segment EBDA and Revenues for the applicable certain item amounts, which are totaled in the tables and described in the footnotes to those tables. Revenues before certain items is provided to further enhance our analysis of Segment EBDA before certain items and is not a performance measure.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues(a)	$9,015	$8,618	$8,005
Operating expenses(b)	(5,353)	(5,457)	(4,393)
Loss on impairments and divestitures, net(c)	(594)	(27)	(200)
Other income	1	1	1
Earnings (losses) from equity investments(d)	474	303	(221)
Other, net(e)	37	49	19
Segment EBDA(a)(b)(c)(d)(e)	3,580	3,487	3,211
Certain items(a)(b)(c)(d)(e)	622	392	825
Segment EBDA before certain items	$4,202	$3,879	$4,036
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$363	$594	
Segment EBDA before certain items	$323	$(157)	
Natural gas transport volumes (BBtu/d)(f)	32,821	29,108	28,095
Natural gas sales volumes (BBtu/d)	2,472	2,341	2,335
Natural gas gathering volumes (BBtu/d)(f)	2,972	2,647	2,963
Crude/condensate gathering volumes (MBbl/d)(f)	307	273	292

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Certain items affecting Segment EBDA

(a) 2018 and 2017 amounts include an increases in revenues of $24 million and $8 million, respectively, and 2016 amount includes a decrease in revenues of $50 million, all related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas, NGL and crude oil sales. 2018 amount also includes increases in revenue of (i) $9 million related to a transportation contract refund; (ii) $5 million related to the early termination of a long-term natural gas transportation contract; and (iii) $4 million from other certain items. 2016 amount also includes an increase in revenue of $39 million associated with revenue collected on a customer's early buyout of a long-term natural gas storage contract.

(b) 2018 amount includes (i) an increase in earnings of $7 million as a result of a property tax refund; (ii) an increase in earnings of $6 million related to the release of certain sales and use tax reserves; and (iii) a decrease in earnings of $2 million related to other certain items. 2017 amount includes a decrease in earnings of (i) $166 million related to the impact of the 2017 Tax Reform; (ii) $3 million related to the non-cash impairment loss associated with the Colden storage field; and (iii) $3 million from other certain items. 2016 amount includes a decrease in earnings of

$3 million from other certain items.

(c) 2018 amount includes a decrease in earnings of $600 million related to a non-cash loss on impairment of certain gathering and processing assets in Oklahoma and an increase in earnings of $1 million related to other certain item. 2017 amount includes a decrease in earnings of $27 million related to the non-cash impairment loss associated with the Colden storage field. 2016 amount includes (i) a decrease in earnings of $106 million of project write-offs; (ii) an $84 million pre-tax loss on the sale of a 50% interest in our SNG natural gas pipeline system; and (iii) an $11 million decrease in earnings from other certain items.

(d) 2018 amount includes (i) 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; (ii) an increase in earnings of $41 million for our share of certain equity investees' 2017 Tax Reform provisional adjustments; and (iii) a decrease in earnings of $4 million related to other certain items. 2017 amount includes (i) a $150 million non-cash impairment loss related to our investment in FEP; (ii) a decrease in earnings of $58 million related to 2017 Tax Reform adjustments recorded by equity investees; (iii) an increase in earnings from an equity investment of $22 million on the sale of a claim related to the early termination of a long-term natural gas transportation contract; (iv) an increase in earnings from an equity investment of $12 million related to a customer contract settlement; (v) a decrease in earnings of $12 million related to early termination of debt at an equity investee; and (vi) a decrease in earnings of $10 million related to a non-cash impairment at an equity investee. 2016 amount includes (i) $606 million of non-cash impairment losses primarily related to our investments in MEP and Ruby; (ii) an increase in earnings of $18 million related to the early termination of a customer contract at an equity investee; and (iii) a decrease in earnings of $12 million related to other certain items at equity investees.

(e) 2018, 2017 and 2016 amounts include decreases in earnings of $24 million, $5 million and $10 million, respectively, related to certain litigation matters.

Other

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

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Midstream	$150	14%	$ 142	3%
West Region	100	11%	95	8%
North Region	43	4%	103	7%
South Region	33	5%	7	2%
Other	(3)	150%	(3)	150%
Intrasegment eliminations	—	—%	19	43%
Total Natural Gas Pipelines	$323	8%	$ 363	4%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- Midstream's increase of $150 million (14%) was primarily due to increased earnings from Texas intrastate natural gas pipeline operations, KinderHawk, Hiland Midstream and South Texas Midstream. Texas intrastate natural gas pipeline operations were favorably impacted by higher volumes with new and existing customers serving the Mexico and Texas Gulf Coast industrial markets partially offset by lower park and loan revenues and storage margins. KinderHawk and South Texas Midstream benefited from increased drilling and production in the Haynesville and Eagle Ford basins, respectively. Hiland Midstream increased earnings were primarily due to higher gas and crude oil volumes and higher NGL sales prices. While these factors also drove an increase in revenue, these increases in revenues were partially offset by the effect of the January 1, 2018 adoption of Topic 606 which caused a corresponding decrease in cost of goods sold;
- West Region's increase of $100 million (11%) was primarily due to higher earnings from EPNG, CIG and CPGPL. EPNG experienced higher volumes in 2018 from increased Permian basin-related activity and associated capacity

sales. CIG and CPGPL earnings were higher due to continued growing production in the Denver Julesburg basin;

- North Region's increase of $43 million (4%) was primarily due to an increase in equity earnings from NGPL, and higher earnings from TGP and KMLP. NGPL increase in earnings was due to increased Permian basin-related activity and lower interest expense resulting from a 2017 refinancing, partially offset by lower storage-related revenue. TGP and KMLP contributed increased earnings primarily from expansion projects recently placed in service; and
- South Region's increase of $33 million (5%) was primarily due to increases in equity earnings from Citrus and SNG, and an increase in earnings from SLNG, partially offset by a decrease in earnings from Southern Gulf LNG due to a loss of revenues from an arbitration ruling calling for a contract termination. Citrus had lower income tax expense due to the 2017 Tax Reform, and SNG increased earnings were from higher transportation revenues from increased system usage and non-recurring 2017 operating expenses. SLNG earnings were driven by higher capitalized AFUDC equity associated with the Elba Liquefaction project.

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Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
South Region	$(143)	(18)%	$ (311)	(48)%
Midstream	(66)	(6)%	887	19%
West Region	(38)	(4)%	(39)	(3)%
North Region	84	7%	84	6%
Other	—	—%	(1)	50%
Intrasegment eliminations	6	100%	(26)	(144)%
Total Natural Gas Pipelines	$(157)	(4)%	$ 594	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 Segment EBDA before certain items in the comparable years of 2017 and 2016:

- South Region's decrease of $143 million (18%) was primarily due to the sale of a 50% interest in SNG to Southern Company on September 1, 2016, partially offset by an increase in earnings from Elba Express primarily due to an expansion project placed in service in December 2016;
- Midstream's decrease of $66 million (6%) was primarily due to decreases in earnings from South Texas Midstream, KinderHawk and Oklahoma Midstream, partially offset by increased earnings from Texas intrastate natural gas pipeline operations and Altamont Midstream. South Texas Midstream lower earnings were primarily due to lower commodity based service revenues and residue gas sales as a result of lower volumes partially offset by higher NGL sales gross margin primarily due to rising NGL prices. KinderHawk experienced lower volumes, which lowered its earnings and Oklahoma Midstream's lower earnings were primarily due to lower volumes and unfavorable producer mix. Texas intrastate natural gas pipeline operations increased earnings were primarily due to higher transportation margins as a result of higher volumes and higher park and loan revenues partially offset by lower storage and sales margins. Altamont Midstream primarily increased earnings were due to higher natural gas and liquids revenues due to higher commodity prices and volumes. Texas intrastate natural gas pipeline operations, Hiland Midstream and Oklahoma Midstream had increases in revenues due to higher commodity prices which was largely offset by a corresponding increases in costs of sales;
- West Region's decrease of $38 million (4%) was primarily due to a decrease in earnings at CIG, partially offset by higher earnings at EPNG. CIG lower earnings were primarily due to a decrease in tariff rates effective January 1, 2017 as a result of a rate case settlement entered into in 2016. EPNG had higher earnings primarily due to higher transportation revenues driven by incremental Permian basin capacity sales and an increase in volumes due to the ramp up of existing customer volumes associated with an expansion project partially offset by increased operations and maintenance expense; and
- North Region's increase of $84 million (7%) was primarily due to higher earnings from TGP and an increase in equity earnings from NGPL. TGP's increase in earnings was primarily due to higher firm transportation revenues driven by incremental capacity sales and expansion projects recently placed in service. NGPL higher earnings were primarily due to lower interest expense due to a reduction in interest rates due to debt refinancing and the repayment of bank borrowings in 2017.

Products Pipelines

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues	$ 1,713	$ 1,661	$ 1,649
Operating expenses(a)	(594)	(487)	(573)
Loss on impairments and divestitures, net(b)	(36)	—	(76)
Other income	2	—	—
Earnings from equity investments(c)	85	58	65
Other, net	3	(1)	2
Segment EBDA(a)(b)(c)	1,173	1,231	1,067
Certain items(a)(b)(c)	61	(38)	113
Segment EBDA before certain items	$ 1,234	$ 1,193	$ 1,180
Change from prior period	Increase/(Decrease)		
Revenues	$ 52	$ 12	
Segment EBDA before certain items	$ 41	$ 13	
Gasoline (MBbl/d)(d)	1,038	1,038	1,025
Diesel fuel (MBbl/d)	372	351	342
Jet fuel (MBbl/d)	302	297	288
Total refined product volumes (MBbl/d)(e)	1,712	1,686	1,655
NGL (MBbl/d)(e)	114	112	109
Crude and condensate (MBbl/d)(e)	345	327	324
Total delivery volumes (MBbl/d)	2,171	2,125	2,088
Ethanol (MBbl/d)(f)	126	117	115

Certain items affecting Segment EBDA

(a) 2018 amount includes (i) an increase in expense of $31 million associated with a certain Pacific operations litigation matter; (ii) an increase in earnings of $5 million as a result of a property tax refund; and (iii) a decrease in expense of $1 million related to other certain items. 2017 amount includes a decrease in expense of $34 million related to a right-of-way settlement and an increase in expense of $1 million related to hurricane repairs. 2016 amount includes increases in expense of $31 million of rate case liability estimate adjustments associated with prior periods and $20 million related to a legal settlement.

(b) 2018 amount includes a decrease in earnings of $36 million associated with a project write-off on the Utica Marcellus Texas pipeline. 2016 amount includes increases in expense of $65 million related to the Palmetto project write-off and $9 million of non-cash impairment charges related to the sale of a Transmix facility.

(c) 2017 amount includes an increase in equity earnings of $5 million related to the impact of the 2017 Tax Reform at an equity investee.2016 amount includes a $12 million gain related to the sale of an equity investment.

Other

(d) Volumes include ethanol pipeline volumes.

(e) Joint Venture throughput is reported at our ownership share.

(f) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
NGLs	$33	27%	$ 4	2%
Southeast Refined Products	26	11%	19	5%
Crude & Condensate	(15)	(4)%	15	4%
West Coast Refined Products	(3)	(1)%	14	2%
Total Products Pipelines	$41	3%	$ 52	3%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- NGLs' increase of $33 million (27%) was primarily due to increases in earnings from Cochin pipeline and to a lesser extent an increase in earnings from equity earnings from Utopia, which went into service in 2018. Cochin's earnings were higher primarily due to foreign exchange transaction losses in 2017 primarily related to an intercompany note receivable, integrity work during 2017 and an expansion project placed in service during 2018;
- Southeast Refined Products' increase of $26 million (11%) was primarily due to increased equity earnings from Plantation pipeline and earnings from South East Terminals. Plantation pipeline earnings were higher primarily due to lower income tax expense due to the 2017 Tax Reform, lower operating expense attributable to a 2017 project write-off and product net gains as a result of higher product prices. South East Terminals earnings were favorably impacted primarily due to higher revenues as a result of expansion projects that were placed into service in the later part of 2017 and higher volumes with existing customers;
- Crude & Condensate's decrease of $15 million (4%) was primarily due to a decrease of earnings from Kinder Morgan Crude & Condensate Pipeline partially offset by an increase of Double H Pipeline earnings. The Kinder Morgan Crude & Condensate Pipeline lower earnings were primarily due to lower services revenues as a result of unfavorable rates on contract renewals partially offset by recognition of deficiency revenue. Double H Pipeline increase in earnings was primarily due to an increase in volumes and the recognition of deficiency revenue; and
- West Coast Refined Products' decrease of $3 million (1%) was primarily due to lower earnings from Pacific operations partially offset by an increase in Calnev earnings. Pacific operations earnings were lower primarily due to higher operating expenses driven by an unfavorable change in product gain/loss, an increase in 2018 environmental reserves and higher fuel and power costs. Calnev earnings were higher due to an increase in services revenues driven by an increase in volumes, the result of an interruption of service by a provider for a competing pipeline that also serves the Las Vegas market.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA	Revenues before certain items

	before certain items increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
West Coast Refined Products	$7	1%	$ 11	2%
NGLs	4	3%	9	5%
Southeast Refined Products	3	1%	(9)	(2)%
Crude & Condensate	(1)	—%	1	—%
Total Products Pipelines	$13	1%	$ 12	1%

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The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- West Coast Refined Products' increase of $7 million (1%) was primarily due to improved earnings at both Pacific operations and Calnev. Pacific operations increase in earnings was primarily due to higher service revenues driven by an increase in volumes partially offset by a volume driven increase in power costs and an increase in right-of-way expense. Calnev earnings were higher primarily due to higher service revenues driven by higher volumes and a decrease in expense related to the reduction of a rate reserve;
- NGLs' increase of $4 million (3%) was primarily due to increased development fee revenues in 2017 for Utopia Pipeline ;
- Southeast Refined Products' increase of $3 million (1%) was primarily due to increased earnings at South East Terminals and to a lesser extent at Transmix processing operations, partially offset by our sale of a 50% interest in Parkway Pipeline on July 1, 2016. South East Terminals increased earnings were primarily due to higher revenues driven by higher volumes as a result of capital expansion projects being placed in service during 2017. The decrease in revenues was driven by lower sales volumes primarily due to the sale of our Indianola plant in August 2016 and lower brokered sales at the Dorsey plant due to an expired contract in May 2017; and
- Crude & Condensate's decrease of $1 million (—%) was primarily due a decrease in earnings on Kinder Morgan Crude & Condensate Pipeline resulting from higher cost of goods sold offset by an increase in earnings from Double Eagle primarily due to higher revenues driven by higher volumes and price.

Terminals

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues(a)	$ 2,019	$ 1,966	$ 1,922
Operating expenses(b)	(818)	(788)	(768)
(Loss) gain on impairments and divestitures, net(c)	(54)	14	(99)
Earnings from equity investments(d)	22	24	19
Other, net	2	8	4
Segment EBDA(a)(b)(c)(d)	1,171	1,224	1,078
Certain items, net(a)(b)(c)(d)	34	(10)	91
Segment EBDA before certain items	$ 1,205	$ 1,214	$ 1,169
Change from prior period	Increase/(Decrease)		
Revenues before certain items	$ 55	$ 68	
Segment EBDA before certain items	$ (9)	$ 45	
Liquids tankage capacity available for service (MMBbl)	90.1	87.6	84.4
Liquids utilization %(e)	93.5%	93.6%	94.7%
Bulk transload tonnage (MMtons)	64.2	59.5	54.8
Ethanol (MMBbl)	61.7	68.1	66.7

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Certain items affecting Segment EBDA

(a) 2018, 2017 and 2016 amounts include increases in revenues of $2 million, $9 million and $28 million, respectively, from the amortization of a fair value adjustment (associated with the below market contracts assumed upon acquisition) from our Jones Act tankers. 2017 amount also includes a decrease in revenues of $5 million related to other certain items.

(b) 2018 amount includes a decrease in expense of $18 million related to hurricane damage insurance recoveries, net of repair costs and an increase in expense of $1 million related to other certain item. 2017 amount includes (i) an increase in expense of $21 million related to hurricane repairs; (ii) a decrease in expense of $10 million related to accrued dredging costs; and (iii) a decrease in expense of $2 million related to other certain items. 2016 amount includes an increase in expense of $3 million related to other certain items.

(c) 2018 amount includes a net loss of $53 million on impairments and divestitures, net, primarily related to our Staten Island terminal. 2017 amount includes a gain of $23 million primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and losses of $8 million related to other divestitures and impairments, net. 2016 amount includes an expense of $109 million related to various losses on impairments and divestitures, net.

(d) 2016 amount includes an increase in earnings of $9 million related to our share of the settlement of a certain litigation matter at an equity investee and a decrease in earnings of $16 million related to various losses on impairments and divestitures of equity investments, net.

Other
(e) The ratio of our tankage capacity in service to tankage capacity available for service.

Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Northeast	$(19)	(15)%	$ (20)	(9)%
Gulf Central	(19)	(22)%	(19)	(15)%
Southeast	(8)	(13)%	(4)	(3)%
Alberta Canada	(1)	(1)%	21	13%
Gulf Liquids	31	11%	37	9%
Midwest	6	8%	7	5%
Marine Operations	3	2%	40	13%
All others (including intrasegment eliminations)	(2)	(1)%	(7)	(2)%
Total Terminals	$(9)	(1)%	$ 55	3%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- decrease of $19 million (15%) from our Northeast terminals primarily due to low utilization at our Staten Island terminal;
- decrease of $19 million (22%) from our Gulf Central terminals primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and the expiration of a crude by rail terminaling contract in August 2018 at our Deer Park Rail Terminal;
- decrease of $8 million (13%) from our Southeast terminals primarily due to the sale of certain terminal assets in December 2017 and higher operating expenses at our steel handling operations;
- decrease of $1 million (1%) from our Alberta Canada terminals primarily due to an increase in operating expenses associated with tank lease fees at our Edmonton South Terminal following the TMPL Sale and the impact of the expiration of a third party crude-by-rail terminaling contract at our Edmonton Rail Terminal joint venture partially offset by an increase in earnings due to the commencement of operations at our Base Line Terminal joint venture;
- increase of $31 million (11%) from our Gulf Liquids terminals primarily driven by contributions from expansion projects at our Pasadena Terminal and the Kinder Morgan Export Terminal as well as organic volume growth at several of our Houston Ship Channel locations;
- increase of $6 million (8%) from our Midwest terminals primarily driven by increased ethanol storage revenues and new liquids customer contracts entered into in 2018; and
- increase of $3 million (2%) from our Marine Operations primarily due to the incremental earnings from the March 2017, June 2017, July 2017 and December 2017 deliveries of the Jones Act tankers, the American Freedom, Palmetto State, American Liberty and American Pride, respectively, partially offset by decreased contributions from existing Jones Act tankers driven by lower charter rates and a reduced operating cost credit attributable to capitalized overhead.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Marine Operations	$42	27%	$ 72	31%
Gulf Liquids	20	8%	38	11%
Alberta, Canada	8	6%	7	5%
Midwest	7	11%	15	11%
Held for sale operations	(19)	(100)%	(55)	(90)%
Gulf Central	(17)	(16)%	(11)	(8)%
All others (including intrasegment eliminations)	4	1%	2	—%
Total Terminals	$45	4%	$ 68	4%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

- increase of $42 million (27%) from our Marine Operations related to the incremental earnings from the May 2016, July 2016, September 2016, December 2016, March 2017, June 2017, July 2017 and December 2017 deliveries of the Jones Act tankers, the Magnolia State, Garden State, Bay State, American Endurance, American Freedom, Palmetto State, American Liberty and American Pride, respectively, partially offset by decreased charter rates on the Golden State, Pelican State, Sunshine State, Empire State and Pennsylvania Jones Act tankers;
- increase of $20 million (8%) from our Gulf Liquids terminals primarily related to higher volumes as a result of various expansion projects, including the recently commissioned Kinder Morgan Export Terminal and North Docks terminal, partially offset by lost revenue associated with Hurricane Harvey-related operational disruptions;
- increase of $8 million (6%) from our Alberta, Canada terminals primarily due to escalations in predominantly fixed, take-or-pay terminaling contracts and a true-up in terminal fees in connection with a favorable arbitration ruling;
- increase of $7 million (11%) from our Midwest terminals primarily driven by increased ethanol throughput revenues in 2017 and a new bulk storage and handling contract entered into fourth quarter 2016;
- decrease of $19 million (100%) from our sale of certain bulk terminal facilities to an affiliate of Watco Companies, LLC in December 2016 and early 2017; and
- decrease of $17 million (16%) from our Gulf Central terminals primarily related to the sale of a 40% membership interest in the Deeprock Development joint venture in July 2017 and the subsequent change in accounting treatment of our retained 11% membership interest as well as lost revenue associated with Hurricane Harvey-related operational disruptions.

CO2

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues(a)	$ 1,255	$ 1,196	$ 1,221
Operating expenses(b)	(453)	(394)	(399)
(Loss) gain on impairments and divestitures, net(c)	(79)	1	(19)
Earnings from equity investments(d)	36	44	24
Segment EBDA(a)(b)(c)(d)	759	847	827
Certain items(a)(b)(c)(d)	148	40	92
Segment EBDA before certain items	$ 907	$ 887	$ 919

Change from prior period	Increase/(Decrease)	
Revenues before certain items	$ 104	$ (43)
Segment EBDA before certain items	$ 20	$ (32)

Southwest Colorado CO_2 production (gross) (Bcf/d)(e)	1.2	1.3	1.2
Southwest Colorado CO_2 production (net) (Bcf/d)(e)	0.6	0.6	0.6
SACROC oil production (gross)(MBbl/d)(f)	29.3	27.9	29.3
SACROC oil production (net)(MBbl/d)(g)	24.4	23.2	24.4
Yates oil production (gross)(MBbl/d)(f)	16.7	17.3	18.4
Yates oil production (net)(MBbl/d)(g)	7.4	7.7	8.2
Katz, Goldsmith, and Tall Cotton Oil Production - Gross (MBbl/d)(f)	8.2	8.1	7.0
Katz, Goldsmith, and Tall Cotton Oil Production - Net (MBbl/d)(g)	7.0	6.9	5.9
NGL sales volumes (net)(MBbl/d)(g)	10.0	9.9	10.3
Realized weighted-average oil price per Bbl(h)	$ 57.83	$ 58.40	$ 61.52
Realized weighted-average NGL price per Bbl(i)	$ 32.21	$ 25.15	$ 17.91

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Certain items affecting Segment EBDA

(a) 2018, 2017 and 2016 amounts include unrealized losses of $90 million and $54 million, and $63 million, respectively, related to derivative contracts used to hedge forecasted commodity sales. 2017 amount also includes an increase in revenues of $9 million related to the settlement of a CO_2 customer sales contract.

(b) 2018 amount includes an increase in earnings of $21 million as a result of a severance tax refund.

(c) 2018 amount includes oil and gas property impairments of $79 million. 2017 and 2016 amounts include a decrease in expense of $1 million and an increase in expense of $20 million, respectively, related to source and transportation project write-offs.

(d) 2017 and 2016 amounts include an increase in equity earnings of $4 million and a decrease in equity earnings of $9 million, respectively, for our share of a project write-off recorded by an equity investee.

Other

(e) Includes McElmo Dome and Doe Canyon sales volumes.

(f) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, an approximately 99% working interest in the Katz unit and a 99% working interest in the Goldsmith Landreth unit and a 100% working interest in the Tall Cotton field.

(g) Net after royalties and outside working interests.

(h) Includes all crude oil production properties.

(i) Includes all NGL sales.

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Below are the changes in both Segment EBDA before certain items and revenues before certain items in 2018 and 2017, when compared with the respective prior year:

Year Ended December 31, 2018 versus Year Ended December 31, 2017

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing activities	$27	5%	$ 45	5%
Source and Transportation activities	(7)	(2)%	52	16%
Intrasegment eliminations	—	—%	7	18%
Total CO_2	$20	2%	$ 104	8%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2018 and 2017:

- increase of $27 million (5%) from our Oil and Gas Producing activities primarily due to increased revenues of $45 million primarily driven by higher NGL prices of $23 million and higher volumes of $22 million partially offset by an increase of $16 million in operating expenses and higher severance tax expense of $2 million; and
- decrease of $7 million (2%) from our Source and Transportation activities primarily due to lower other revenues of $5 million, higher ad valorem tax expense of $4 million and decreased earnings from an equity investee of $3 million partially offset by higher CO_2 sales of $3 million driven by higher contract sales prices of $25 million offset by lower volumes of $22 million and lower operating expenses of $2 million. The increase in revenues of $52 million is primarily due to the effect of the January 1, 2018 adoption of Topic 606, which increased both revenues and operating expenses (costs of sales) by $54 million, as discussed in Note 16 “Revenue Recognition” to our consolidated financial statements.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

	Segment EBDA before certain items increase/(decrease)		Revenues before certain items increase/(decrease)	
	(In millions, except percentages)			
Source and Transportation activities	$2	1%	$ (9)	(3)%
Oil and Gas Producing activities	(34)	(6)%	(33)	(3)%
Intrasegment eliminations	—	—%	(1)	(3)%
Total CO_2	$(32)	(3)%	$ (43)	(3)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Segment EBDA before certain items in the comparable years of 2017 and 2016:

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increase of $2 million (1%) from our Source and Transportation activities primarily due to increased earnings from an equity investee of $6 million and lower operating expenses of $5 million partially offset by lower revenues of $9 million driven by lower contract sales prices of $7 million and decreased volumes of $2 million; and

- decrease of $34 million (6%) from our Oil and Gas Producing activities primarily due to decreased revenues of $33 million driven by lower volumes of $22 million and lower commodity prices of $11 million, and higher operating expenses of $1 million.

Kinder Morgan Canada

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except operating statistics)		
Revenues	$ 170	$ 256	$ 253
Operating expenses	(72)	(95)	(87)
Gain on divestiture(a)	596	—	—
Other, net	26	25	15
Segment EBDA(a)	720	186	181
Certain items(a)	(596)	—	—
Segment EBDA before certain items	$ 124	$ 186	$ 181
Change from prior period	Increase/(Decrease)		
Revenues	$ (86)	$ 3	
Segment EBDA before certain items	$ (62)	$ 5	
Transport volumes (MBbl/d)(b)	291	308	316

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Certain items affecting Segment EBDA

(a) 2018 amount includes a gain of $596 million on the TMPL Sale.

Other

(b) Represents TMPL average daily volumes reported until date of sale, August 31, 2018.

For the comparable years of 2018 and 2017, the Kinder Morgan Canada business segment had a decrease in Segment EBDA of $62 million (33%) primarily due to the TMPL Sale on August 31, 2018 sale. As a result of the TMPL Sale on August 31, 2018, this business segment does not have results of operations on a prospective basis.

For the comparable years of 2017 and 2016, the Kinder Morgan Canada business segment had an increase in Segment EBDA of $5 million (3%) and an increase in revenues of $3 million (1%) primarily due to (i) higher capitalized equity financing costs due to spending on the TMEP; (ii) currency translation gains due to the strengthening of the Canadian dollar; and (iii) higher incentive revenues partly offset by lower state of Washington volumes and operating expense timing changes.

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

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
General and administrative and corporate charges(a)	$588	$660	$652
Certain items(a)	(24)	(15)	13
General and administrative and corporate charges before certain items(a)	$564	$645	$665
Interest, net(b)	$1,917	$1,832	$1,806
Certain items(b)	(26)	39	193
Interest, net, before certain items(b)	$1,891	$1,871	$1,999
Net income attributable to noncontrolling interests(c)	$310	$40	$13
Noncontrolling interests associated with certain items(c)	(240)	—	8
Net income attributable to noncontrolling interests before certain items(c)	$70	$40	$21

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Certain items

(a) 2018 amount includes: (i) an increase in expense of $10 million associated with an estimated environmental reserve adjustment; (ii) a decrease in expense of $12 million related to the release of certain sales and use tax reserves; (iii) an increase in expense of $10 million of asset sale related costs; (iv) an increase in expense of $9 million related to certain corporate litigation matters; and (v) an increase in expense of $7 million related to other certain items. 2017 amount includes: (i) an increase in expense of $10 million for acquisition and divestiture related costs; (ii) an increase in expense of $4 million related to certain corporate litigation matters; (iii) an increase in expense of $5 million related to a pension settlement; and (iv) a decrease in expense of $4 million related to other certain items. 2016 amount includes increases in expense of (i) $14 million related to severance costs; and (ii) $12 million related to acquisition and divestiture costs; offset by decreases in expense of (i) $34 million related to certain corporate litigation matters; and (ii) $5 million related to other certain items.

(b) 2018, 2017 and 2016 amounts include: (i) decreases in interest expense of $32 million, $44 million and $115 million, respectively, related to amortization of non-cash debt fair value adjustments associated with acquisitions and (ii) an increase of $9 million and decreases of $3 million and $44 million, respectively, in interest expense related to non-cash true-ups of our estimates of swap ineffectiveness. 2018 amount also includes increases in interest expense of $47 million related to the write-off of capitalized KML credit facility fees and $2 million related to other certain items. 2017 amount also includes an $8 million increase in interest expense related to other certain items. 2016 amount also includes a $34 million decrease in interest expense related to certain litigation matters.

(c) 2018 amount is primarily associated with the $596 million gain on the TMPL Sale and is disclosed above in "—Kinder Morgan Canada." The 2016 amount is associated with Natural Gas Pipelines segment certain items and disclosed above in "—Natural Gas Pipelines."

General and administrative expenses and corporate charges before certain items decreased $81 million in 2018 and $20 million in 2017 when compared with the respective prior year. The decrease in 2018 as compared to 2017 was primarily due to higher capitalized costs of $54 million driven by the 2018 construction of Elba Liquefaction, Gulf Coast and Hiland facilities offset by lower spending on TGP, lower vacation and labor accruals of $18 million and $7 million from the sale of TMPL. The decrease in 2017 as compared to 2016 was primarily driven by the sale of a 50% interest in our SNG natural gas pipeline system (effective September 1, 2016), higher capitalized costs, lower state franchise taxes, legal and insurance costs, partially offset by higher labor accruals and pension costs.

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 before certain items, increased $20 million in 2018 and decreased $128 million in 2017 when compared with the respective prior year. The increase in interest expense in 2018 as compared to 2017 was primarily due to higher short-term interest rates and higher short-term debt balance partially offset by lower average long-term debt balance. The decrease in interest expense in 2017 as compared to 2016 was primarily due to lower weighted average debt balances as proceeds from the May 2017 KML IPO and our September 2016 sale of a 50% interest in SNG were used to pay down debt, partially offset by a slightly higher overall weighted average interest rate on our outstanding debt.

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, 2018 and 2017, approximately 31% and 28%, 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 before certain items increased $30 million in 2018 and $19 million in 2017 when compared with the respective prior year. The increases were primarily due to the May 30, 2017 sale of approximately 30% of our Canadian business operations to the public in the KML IPO.

Income Taxes

Year Ended December 31, 2018 versus Year Ended December 31, 2017

Our tax expense for the year ended December 31, 2018 is approximately $587 million, as compared with 2017 tax expense of $1,938 million. The $1,351 million decrease in tax expense is primarily due to (i) the decrease in the federal income tax rate as a result of the 2017 Tax Reform; and (ii) the decrease in uncertain tax positions as a result of audit settlements; partially offset by (i) the tax impact on the TMPL Sale; and (ii) the decrease of enhanced oil recovery credits.

Year Ended December 31, 2017 versus Year Ended December 31, 2016

Our tax expense for the year ended December 31, 2017 is approximately $1,938 million, as compared with 2016 tax expense of $917 million. The $1,021 million increase in tax expense is primarily due to (i) an increase in year-over-year earnings as a result of fewer asset impairments and project write-offs in 2017; and (ii) higher tax expense as a result of the 2017 Tax Reform. These increases are partially offset by (i) the 2016 impact of our Regulated Natural Gas Pipelines business segment's $817 million non-tax-deductible goodwill as a result of the sale of a 50% interest in SNG; and (ii) the recognition of enhanced oil recovery credits.

Liquidity and Capital Resources

General

As of December 31, 2018, we had $3,280 million of "Cash and cash equivalents," an increase of $3,016 million (1,142%) from December 31, 2017. 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 $5,043 million and $4,601 million in 2018 and 2017, respectively. The year-to-year increase 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.

Additionally, during 2018 the TMPL Sale mentioned above in "—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project" was a source of liquidity and the primary driver of cash on hand as of December 31, 2018.

On January 3, 2019, pursuant to KML's shareholders' approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see "—KML 2018 Credit Facility" following). KML's public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximately 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately repay our outstanding commercial paper borrowings of $0.4 million and in February 2019 to pay down approximately $1.3 billion of maturing long-term debt. To facilitate the return of capital and provide flexibility for KML's dividends going forward, KML's shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, along with a "reverse stock split" of KML's restricted voting shares, and KML's special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

KML 2018 Credit Facility

Upon the closing of the TMPL Sale on August 31, 2018, KML established a 4-year, C$500 million unsecured revolving credit facility (the "KML 2018 Credit Facility") for working capital purposes, replacing a temporary credit facility that was put in place following the announcement of the TMPL Sale on May 30, 2018 (the "KML Temporary Credit Facility"). The C$133 million (U.S.$102 million) of outstanding borrowings under the KML Temporary Credit Facility were paid off prior to its termination with a portion of the proceeds from the TMPL Sale. As of December 31, 2018, there were no outstanding borrowings under the KML 2018 Credit Facility.

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.

As of December 31, 2018, our short-term corporate debt ratings were A-3 (upgraded to A-2 on January 7, 2019), Prime-2 and F3 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively. We are on a positive outlook for an upgrade by Fitch Ratings, Inc.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2018.

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

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(a) Subsequently was upgraded to BBB on January 7, 2019 with a Stable outlook.

Short-term Liquidity

As of December 31, 2018, our principal sources of short-term liquidity are (i) our $4.5 billion revolving credit facilities and associated $4.0 billion commercial paper program; (ii) the KML 2018 Credit Facility (for the purposes described above); and (iii) cash from operations. 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. Borrowings under our commercial paper program and letters of credit reduce borrowings allowed under ours and KML's respective credit facilities. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility (see Note 9 "Debt—Credit Facilities and Restrictive Covenants—KMI" to our consolidated financial statements) and, as previously discussed, we have consistently generated strong cash flows from operations.

As of December 31, 2018, our $3,388 million of short-term debt consisted primarily of (i) $433 million outstanding under our $4.0 billion commercial paper program; and (ii) $2,800 million of senior notes that mature in the next year. As previously discussed, we repaid $1.7 billion of this short-term debt in 2019 from a portion of the TMPL Sale proceeds. We intend to refinance our remaining short-term debt through credit facility borrowings, commercial paper borrowings, or by issuing new long-term debt or paying down short-term debt using cash retained from operations. Our short-term debt balance as of December 31, 2017 was $2,828 million.

We had working capital (defined as current assets less current liabilities) deficits of $1,835 million and $3,466 million as of December 31, 2018 and 2017, 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 $1,631 million (47%) favorable change from year-end 2017 was primarily due to: (i) the $2,998 million of proceeds from the TMPL Sale, net of cash disposed, partially offset by (i) the $890 million (C$1,195 million) distribution paid to our noncontrolling interests associated with KML on January 3, 2019 ($876 million was the accrued U.S.$ value as of December 31, 2018) and a $516 million increase in current maturities of our senior notes. 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.

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 growth projects for the foreseeable future. Furthermore, through January 2019, we have 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 the debt of each other. See Note 20 “Guarantee of Securities of Subsidiaries” to our consolidated financial statements. As of December 31, 2018 and 2017, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $33,205 million and $34,088 million, respectively. For more information regarding our debt-related transactions in 2018, 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 2018 and early 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—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. See "—Common Dividends" and "—Preferred Dividends."

Our capital expenditures for the year ended December 31, 2018, and the amount we expect to spend for 2019 to sustain and grow our business are as follows (in millions):

	2018	Expected 2019
Sustaining capital expenditures(a)(b)	$652	$ 715
KMI Discretionary capital investments(b)(c)(d)	$2,363	$ 3,085
KML Discretionary capital investments(b)(e)	$401	$ 24

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(a) 2018 and Expected 2019 amounts include $105 million and $127 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) 2018 includes $128 million of net changes from accrued capital expenditures, contractor retainage, and other.

(c) 2018 amount includes $279 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.

(e) 2018 amount includes TMEP capital investments for the period ending on August 31, 2018, the closing of the TMPL Sale.

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)	$36,593	$ 3,388	$4,627	$5,768	$ 22,810
Interest payments(b)	24,493	1,890	3,418	2,992	16,193
Leases and rights-of-way obligations(c)	862	122	209	178	353
Pension and postretirement welfare plans(d)	925	67	40	41	777
Transportation, volume and storage agreements(e)	928	168	307	205	248
Other obligations(f)	276	65	84	35	92
Total	$64,077	$ 5,700	$8,685	$9,219	$ 40,473
Other commercial commitments:					
Standby letters of credit(g)	$156	$ 83	$73	$—	$ —
Capital expenditures(h)	$304	$ 304	$—	$—	$ —

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(a) Less than 1 year amount primarily includes $3,277 million of current maturities on senior notes and $111 million associated with our Trust I Preferred Securities that are classified as current obligations because these securities have rights to convert into cash and/or KMI common stock. 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, 2018.

(c) Represents commitments pursuant to the terms of operating lease agreements and liabilities for rights-of-way.

(d) Represents the amount by which the benefit obligations exceeded the fair value of plan assets at year-end for pension and other postretirement benefit plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets. The payments by period include expected contributions to funded plans in 2019 and estimated benefit payments for unfunded plans in all years.

(e) Primarily represents transportation agreements of $374 million, volume agreements of $338 million and storage agreements for capacity of $183 million.

(f) Primarily includes 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 liabilities are included within “Accrued contingencies” and “Other long-term liabilities and deferred credits” in our consolidated balance sheets.

(g) The $156 million in letters of credit outstanding as of December 31, 2018 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 nine letters of credit for insurance purposes; (iii) a $24 million letter of credit supporting our Kinder Morgan Operating L.P. “B” tax-exempt bonds; (iv) thirteen letters of credit totaling $8 million supporting our pipeline and terminal operations in Canada; and (v) a combined $45 million in twenty-five 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, 2018.

Cash Flows

Operating Activities

The net increase of $442 million (10%) in cash provided by operating activities in 2018 compared to 2017 was primarily attributable to:

- a $346 million increase in cash associated with net changes in working capital items and other non-current assets and liabilities, primarily driven, among other things, by a $137 income tax refund received in the 2018 period, and an increase in current income tax liabilities associated with the tax gain on the TMPL Sale in the 2018 period. These increases were partially offset by higher payments for litigation matters in the 2018 period compared with the 2017 period; and
- a $96 million increase in operating cash flow resulting from the combined effects of adjusting the $1,696 million increase in net income for the period-to-period net changes in non-cash items including the following: (i) loss on impairments and divestitures, net (see discussion above in “—Results of Operations”); (ii) loss on impairments and divestitures of equity investments, net (see discussion above in “—Results of Operations”); (iii) the change in fair market value of derivative contracts; (iv) DD&A expenses (including amortization of excess cost of equity investments); (v) deferred income taxes; (vi) earnings from equity investments; and (vii) loss on early extinguishment of debt.

Investing Activities

The $3,335 million net decrease in cash used in investing activities in 2018 compared to 2017 was primarily attributable to:

- a $2,998 million increase in cash reflecting proceeds received from the TMPL Sale, net of cash disposed in the 2018 period. See Note 3 “Divestitures and Acquisition” for further information regarding this transaction;
- a $284 million decrease in capital expenditures in the 2018 period over the comparative 2017 period primarily due to lower expenditures in our Terminals business segment, partially offset by higher expenditures related to construction projects in our Natural Gas Pipelines business segment;
- a $251 million decrease in cash used for contributions to equity investments primarily due to lower contributions we made to NGPL Holdings LLC, FEP and Utopia Holding LLC in the 2018 period compared to the 2017 period, partially offset by the contributions made to Gulf Coast Express Pipeline LLC in the 2018 period; and
- a $124 million increase in cash proceeds received from the sale of equity investments, primarily driven by a sale of our partial interest in Gulf Coast Express LLC in the 2018 period; partially offset by,
- a $138 million decrease in cash proceeds from sale of property, plant and equipment and other net assets in the 2018 period compared to the 2017 period; and
- a $137 million decrease in cash resulting from lower distributions received from equity investments in excess of cumulative earnings, primarily from MEP, SNG and Citrus Corporation in the 2018 period over the comparative 2017 period.

Financing Activities

The net increase of $143 million in cash used by financing activities in 2018 compared to 2017 was primarily attributable to:

- a combined $1,665 million decrease in cash reflecting $1,245 million net proceeds we received from the KML IPO in May 2017 and $420 million net proceeds received from the KML preferred share issuances in the 2017 period;
- a $498 million increase in dividend payments to our common shareholders;

- a $304 million decrease in cash due to lower contributions received from EIG in the 2018 period compared to the 2017 period as the 2017 period included $386 million we received from EIG Global Energy Partners for our sale of a 49% partnership interest in ELC;
- a $36 million increase in distributions to noncontrolling interests, primarily to KML restricted share holders and preferred shareholders; and
- a $23 million increase in cash used for common shares repurchased under our common share buy-back program in the 2018 period compared to the 2017 period; partially offset by,
- a $2,384 million net increase in cash related to debt activity as a result of $118 million of net debt issuances in the 2018 period compared to $2,266 million of net debt payments in the 2017 period. See Note 9 “Debt” for further information regarding our debt activity.

Mandatory Convertible Preferred Stock

As of October 26, 2018, all of our issued and outstanding 1,600,000 shares of 9.750% 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 current market price of our common stock at the time of conversion, our Series A Preferred Shares converted into 58 million common shares.

Dividends and Stock Buy-back Program
KMI 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 9.750% 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.

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
January 26, 2018 through April 25, 2018	$24.375	January 17, 2018	April 11, 2018	April 26, 2018
April 26, 2018 through July 25, 2018	24.375	April 18, 2018	July 11, 2018	July 26, 2018
July 26, 2018 through October 25, 2018	24.375	July 18, 2018	October 11, 2018	October 26, 2018

KMI Common Stock Dividends
The table below reflects the declaration of common stock dividends of $0.80 per common share for 2018.

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2018	$0.20	April 18, 2018	April 30, 2018	May 15, 2018
June 30, 2018	0.20	July 18, 2018	July 31, 2018	August 15, 2018
September 30, 2018	0.20	October 17, 2018	October 31, 2018	November 15, 2018
December 31, 2018	0.20	January 16, 2019	January 31, 2019	February 15, 2019

We will continue to return additional value to our shareholders in 2019 through our previously announced dividend increase. We plan to increase our dividend to $1.00 per common share in 2019 and $1.25 per common share in 2020, a growth rate of 25% annually.

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, 2018 and 2017, we repurchased approximately 15 million and 14 million, respectively, of our Class P shares for approximately $273 million and $250 million, respectively. 2018 amounts exclude repurchases made in December 2018 of approximately 0.1 million of our Class P shares for approximately $2 million, which settled on January 2, 2019.

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,	
	2018	2017
KML(a)	$514	$1,163
Others	339	325
	$853	$1,488

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(a) The reduction in the noncontrolling interests associated with KML is primarily attributable to the accrual of the return of capital distribution for the net proceeds from the TMPL Sale paid to KML’s Restricted Voting Shareholders on January 3, 2019 of approximately $0.9 billion. For more information see “—General—KML—Sale of Trans Mountain Pipeline System and Its Expansion Project” above.

KML Distributions

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its distributable cash flow. The payment of dividends is not guaranteed, and the amount and timing of any dividends payable will be at the discretion of KML’s board of directors. KML intends to pay quarterly dividends, if any, on or about the 45th day (or next business day) following the end of each calendar quarter to holders of its restricted voting shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter. KML also established a Dividend Reinvestment Plan (DRIP) that allows holders (excluding holders not resident in Canada) of restricted voting shares to elect to have any or all cash dividends payable to such shareholder automatically reinvested in additional restricted voting shares at a price per share calculated by reference to the volume-weighted average of the closing price of the restricted voting shares on the stock exchange on which the restricted voting shares are then listed for the five trading days immediately preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by KML’s board of directors, in its sole discretion).

On January 16, 2019, KML’s board of directors announced that it would suspend KML’s DRIP, effective with the payment of the fourth quarter 2018 dividend on February 15, 2019, in light of KML’s reduced need for capital.

For 2019, KML announced that it expects to pay an annual dividend of C$0.65 per split-adjusted restricted voting share.

KML also pays dividends on its 12,000,000 Series 1 Preferred Shares and 10,000,000 Series 3 Preferred Shares, which are fixed, cumulative, preferential, and payable quarterly in the annual amount of C$1.3125 per share and

C$1.3000 per share, respectively, on the 15th day of February, May, August and November, as and when declared by KML's board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively.

During the year ended December 31, 2018, KML paid dividends on its Restricted Voting Shares to the public valued at $52 million, of which $38 million was paid in cash. The remaining value of $14 million for the year ended December 31, 2018 was paid in 1,092,791 KML Restricted Voting Shares. KML also paid dividends to the public on its Series 1 and Series 3 Preferred Shares of $21 million for the year ended December 31, 2018.

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 natural gas, NGL and crude oil. 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.

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 and natural gas, 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.

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+
Wells Fargo	A+
Bank of Nova Scotia	A+
Canadian Imperial Bank	A+
JP Morgan	A+

As discussed above, the principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, NGL and crude oil. 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. 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.

We measure the risk of price changes in the crude oil, natural gas and NGL derivative instruments 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. A hypothetical 10% movement in the underlying commodity prices would have the following effect on the associated derivative contracts' estimated fair value (in millions):

	As of December 31,	
Commodity derivative	2018	2017
Crude oil	$97	$125
Natural gas	12	15
NGL	6	10
Total	$115	$150

As discussed above, we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore 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.

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 KMGP, and sensitivity to interest rates (in millions):

	December 31, 2018		December 31, 2017	
	Carrying value	Estimated fair value(c)	Carrying value	Estimated fair value(c)
Fixed rate debt(a)	$36,480	$ 36,647	$37,041	$ 39,255
Variable rate debt	$844	$ 822	$802	$ 795
Notional principal amount of fixed-to-variable interest rate swap agreements	10,575		9,575	
Debt balances subject to variable interest rates(b)	$11,419		$10,377	

(a) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2018 and 2017, would result in changes of approximately $1,638 million and $1,525 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 52 and 50 basis points, respectively, in 2018 and 2017) when applied to our outstanding balance of variable rate debt as of

December 31, 2018 and 2017, including adjustments for the notional swap amounts described above, would result in changes of approximately $59 million and $52 million, respectively, in our 2018 and 2017 annual pre-tax earnings.

(c) Fair values were determined using quoted market prices, where applicable, or future cash flows discounted at market rates for similar types of borrowing arrangements.

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, 2018, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 31% of our debt balances were subject to variable interest rates.

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

Foreign Currency Risk

As of December 31, 2018, 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.

As of December 31, 2018, we had a notional principal amount of C$2,450 million (U.S.$1,888 million) of cross-currency swap agreements that result in our selling fixed C$ and receiving fixed U.S.$. These swaps effectively hedged the foreign currency risk associated with a substantial portion of our share of the TMPL Sale proceeds that KML distributed to us on January 3, 2019, at which time the cross-currency currency swaps also expired.

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 72.

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, 2018, 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, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018, 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 2018 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 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

Item 11. Executive Compensation.
The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

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 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

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 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

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 2019 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2019.

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 72.

(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 three months 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))

Exhibit Number		Description
3.3	*	Certificate of Elimination of 9.75% Series A Mandatory Convertible Preferred Stock of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K filed January 22, 2019 (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 three Months 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))
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 (contained 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))

Exhibit Number	Description
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 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 9.00% Senior Notes due 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008 (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 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))
4.24*	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 5.80% 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))
4.25*	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 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))
4.26*	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 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))
4.27*	

	Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))
4.28*	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))
4.29*	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))
4.30*	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))

Exhibit Number		Description
4.31	*	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))
4.32	*	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 three months ended March 31, 2015 (File No. 001-35081))
4.33	*	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))
4.34	*	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))
4.35	*	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))
4.36	*	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))
4.37		Certain instruments with respect to long-term debt of KMI and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of KMI and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. KMI hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
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 three months 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))
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 three months 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 three months 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 three months 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 three months 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 three months 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 three months 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 three months 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))

Exhibit Number	Description
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
10.15	364-Day Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders party thereto
10.16	Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2018
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: (i) our Consolidated Statements of Income for the years ended December 31, 2018, 2017, and 2016; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2018, 2017, and 2016; (iii) our Consolidated Balance Sheets as of December 31, 2018 and 2017; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017, and 2016; (v) our Consolidated Statement of Stockholders’ Equity as of and for the years ended December 31, 2018, 2017, and 2016; and (vi) the notes to our Consolidated Financial Statements

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Kinder Morgan, Inc. and its subsidiaries (the “Company”) as of December 31, 2018 and 2017 and the related consolidated statements of income, comprehensive income, cash flows, and stockholders’ equity for each of the three years in the period ended December 31, 2018, 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, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2018 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, 2018, 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.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 8, 2019

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,		
	2018	2017	2016
Revenues			
Natural gas sales	$3,281	$3,053	$2,454
Services	7,931	7,901	8,146
Product sales and other	2,932	2,751	2,458
Total Revenues	14,144	13,705	13,058
Operating Costs, Expenses and Other			
Costs of sales	4,421	4,345	3,429
Operations and maintenance	2,522	2,472	2,372
Depreciation, depletion and amortization	2,297	2,261	2,209
General and administrative	601	688	703
Taxes, other than income taxes	345	398	421
Loss on impairments and divestitures, net	167	13	387
Other income, net	(3)	(1)	(1)
Total Operating Costs, Expenses and Other	10,350	10,176	9,520
Operating Income	3,794	3,529	3,538
Other Income (Expense)			
Earnings from equity investments	887	578	497
Loss on impairments and divestitures of equity investments, net	(270)	(150)	(610)
Amortization of excess cost of equity investments	(95)	(61)	(59)
Interest, net	(1,917)	(1,832)	(1,806)
Other, net	107	97	78
Total Other Expense	(1,288)	(1,368)	(1,900)
Income Before Income Taxes	2,506	2,161	1,638
Income Tax Expense	(587)	(1,938)	(917)
Net Income	1,919	223	721
Net Income Attributable to Noncontrolling Interests	(310)	(40)	(13)
Net Income Attributable to Kinder Morgan, Inc.	1,609	183	708
Preferred Stock Dividends	(128)	(156)	(156)
Net Income Available to Common Stockholders	$1,481	$27	$552
Class P Shares			
Basic and Diluted Earnings Per Common Share	$0.66	$0.01	$0.25
Basic and Diluted Weighted Average Common Shares Outstanding	2,216	2,230	2,230

Dividends Per Common Share Declared for the Period	$0.80	$0.50	$0.50

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,		
	2018	2017	2016
Net income	$ 1,919	$ 223	$ 721
Other comprehensive income (loss), net of tax			
Change in fair value of hedge derivatives (net of tax (expense) benefit of $(34), $(82) and $60, respectively)	111	145	(104)
Reclassification of change in fair value of derivatives to net income (net of tax (expense) benefit of $(25), $97 and $67, respectively)	84	(171)	(116)
Foreign currency translation adjustments (net of tax expense of $16, $56 and $20, respectively)	141	101	34
Benefit plan adjustments (net of tax (expense) benefit of $(11), $(27) and $19, respectively)	2	40	(14)
Total other comprehensive income (loss)	338	115	(200)
Comprehensive income	2,257	338	521
Comprehensive income attributable to noncontrolling interests	(328)	(86)	(13)
Comprehensive income attributable to KMI	$ 1,929	$ 252	$ 508

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, 2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$3,280	$264
Restricted deposits	51	62
Accounts receivable, net	1,498	1,448
Fair value of derivative contracts	260	114
Inventories	385	424
Income tax receivable	23	165
Other current assets	225	238
Total current assets	5,722	2,715
Property, plant and equipment, net	37,897	40,155
Investments	7,481	7,298
Goodwill	21,965	22,162
Other intangibles, net	2,880	3,099
Deferred income taxes	1,566	2,044
Deferred charges and other assets	1,355	1,582
Total Assets	$78,866	$79,055
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS’ EQUITY		
Current liabilities		
Current portion of debt	$3,388	$2,828
Accounts payable	1,337	1,340
Distributions payable to KML noncontrolling interests	876	—
Accrued interest	579	621
Accrued taxes	483	256
Accrued contingencies	88	291
Other current liabilities	806	845
Total current liabilities	7,557	6,181
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	33,105	33,988
Preferred interest in general partner of KMP	100	100
Debt fair value adjustments	731	927
Total long-term debt	33,936	35,015
Other long-term liabilities and deferred credits	2,176	2,735
Total long-term liabilities and deferred credits	36,112	37,750
Total Liabilities	43,669	43,931
Commitments and contingencies (Notes 9, 13 and 18)		
Redeemable Noncontrolling Interest	666	—
Stockholders’ Equity		
	—	—

Preferred stock, $0.01 par value, 10,000,000 shares authorized, 9.75% Series A Mandatory Convertible, $1,000 per share liquidation preference, - and 1,600,000 shares, respectively, issued and outstanding		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,262,165,783 and 2,217,110,072 shares, respectively, issued and outstanding	23	22
Additional paid-in capital	41,701	41,909
Retained deficit	(7,716)	(7,754)
Accumulated other comprehensive loss	(330)	(541)
Total Kinder Morgan, Inc.'s stockholders' equity	33,678	33,636
Noncontrolling interests	853	1,488
Total Stockholders' Equity	34,531	35,124
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$78,866	$79,055

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,		
	2018	2017	2016
Cash Flows From Operating Activities			
Net income	$ 1,919	$ 223	$ 721
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,297	2,261	2,209
Deferred income taxes	405	2,073	1,087
Amortization of excess cost of equity investments	95	61	59
Change in fair market value of derivative contracts	77	40	64
Loss (gain) on early extinguishment of debt	—	4	(45)
Loss on impairments and divestitures, net (Note 4)	167	13	387
Loss on impairments and divestitures of equity investments, net (Note 4)	270	150	610
Earnings from equity investments	(887)	(578)	(497)
Distributions of equity investment earnings	499	426	431
Changes in components of working capital, net of the effects of acquisitions and dispositions			
Accounts receivable, net	(50)	(78)	(107)
Income tax receivable	137	7	(148)
Inventories	15	(90)	49
Other current assets	(16)	(25)	(81)
Accounts payable	21	73	144
Accrued interest, net of interest rate swaps	(22)	10	(18)
Accrued taxes	241	(37)	31
Accrued contingencies and other current liabilities	73	138	11
Rate reparations, refunds and other litigation reserve adjustments	(202)	(100)	(32)
Other, net	4	30	(117)
Net Cash Provided by Operating Activities	5,043	4,601	4,758
Cash Flows From Investing Activities			
Proceeds from the TMPL Sale, net of cash disposed (Note 3)	2,998	—	—
Acquisitions of assets and investments	(39)	(4)	(333)
Capital expenditures	(2,904)	(3,188)	(2,882)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,401
Proceeds from sales of equity investments	124	—	—
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	(20)	118	330
Contributions to investments	(433)	(684)	(408)
Distributions from equity investments in excess of cumulative earnings	237	374	231
Loans (to) from related parties	(31)	(23)	35
Other, net	—	4	1
Net Cash Used in Investing Activities	(68)	(3,403)	(1,625)
Cash Flows From Financing Activities			
Issuances of debt	14,751	8,868	8,629
Payments of debt	(14,591)	(11,064)	(10,060)
Debt issue costs	(42)	(70)	(19)
Cash dividends - common shares (Note 11)	(1,618)	(1,120)	(1,118)

Cash dividends - preferred shares (Note 11)	(156)	(156)	(154)
Repurchases of common shares (Note 11)	(273)	(250)	—
Contributions from investment partner	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	19	12	117
Distributions to noncontrolling interests	(78)	(42)	(24)
Other, net	(17)	(9)	(8)
Net Cash Used in Financing Activities	(1,824)	(1,681)	(2,637)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	(146)	22	2
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	3,005	(461)	498
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787	289
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 3,331	$ 326	$ 787

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

	Year Ended December 31,		
	2018	2017	2016
Cash and Cash Equivalents, beginning of period	$ 264	$ 684	$ 229
Restricted Deposits, beginning of period	62	103	60
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	326	787	289
Cash and Cash Equivalents, end of period	3,280	264	684
Restricted Deposits, end of period	51	62	103
Cash, Cash Equivalents, and Restricted Deposits, end of period	3,331	326	787
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	$ 3,005	$ (461)	$ 498
Noncash Investing and Financing Activities			
Assets acquired by the assumption or incurrence of liabilities	$ —	$ —	$ 43
Net assets contributed to equity investments	—	—	37
Increase in property, plant and equipment from both accruals and contractor retainage	30	14	
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)	1,879	1,854	2,050
Cash (refunded) paid during the period for income taxes, net	(109)	(140)	4

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

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

	Common stock		Preferred stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Retained deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2015	2,229	$ 22	2	$ —	$ 41,661	$ (6,103)	$ (461)	$ 35,119	$ 284	$ 35,403
Restricted shares	1				66			66		66
Net income						708		708	13	721
Distributions								—	(24)	(24)
Contributions								—	117	117
Preferred stock dividends						(156)		(156)		(156)
Common stock dividends						(1,118)		(1,118)		(1,118)
Other					12			12	(19)	(7)
Other comprehensive loss							(200)	(200)		(200)
Balance at December 31, 2016	2,230	22	2	—	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	2,217	22	2	—	$ 41,909	$ (7,754)	$ (541)	$ 33,636	$ 1,488	35,124
Impact of adoption of ASUs (Note 2)						175	(109)	66		66
Balance at January 1, 2018	2,217	22	2	—	41,909	(7,579)	(650)	33,702	1,488	35,190
Repurchases of shares	(15)				(273)			(273)		(273)
Mandatory conversion of preferred shares	58	1	(2)		(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

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

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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, CO_2 and other products, and our terminals transload and store liquid commodities including petroleum products, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores.

Our common stock trades on the NYSE under the symbol “KMI.”

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.

Adoption of New Accounting Pronouncements

On January 1, 2018, we adopted Accounting Standards Updates (ASU) No. 2014-09, “Revenue from Contracts with Customers” and a series of related accounting standard updates designed to create improved revenue recognition and disclosure comparability in financial statements. For more information, see “—Revenue Recognition” below and Note 16.

On January 1, 2018, we retroactively adopted ASU No. 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force).” This ASU requires the statements of cash flows to present the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are now included with cash and cash equivalents when reconciling the beginning of period and end of period amounts presented on the statements of cash flows. The retrospective application of this new accounting guidance resulted in an increase of $41 million and a decrease of $43 million in “Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits”, no change and a decrease of $37 million in “Accrued contingencies and other current liabilities” in Cash Flows from Operating Activities, and a decrease of $41 million and an increase of $80 million in “Other, net” in Cash Flows from Investing Activities in our accompanying consolidated statement of cash flows for the years ended December 31, 2017 and 2016, respectively, from what was previously presented in our Annual Report on Form 10-K for the year ended December 31, 2017.

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 and other insurance subsidiaries, and cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions.

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 "Retained deficit" balance. The cumulative effect of the adoption of this ASU was a $66 million, net of income taxes, adjustment to our "Retained deficit" balance as presented in our consolidated statement of stockholders' equity for the year ended December 31, 2018. This ASU also requires 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 sheet as of December 31, 2018, as EIG has the right under certain conditions to redeem their interests for cash. The December 31, 2017 balance of $485 million is included in “Other long-term liabilities and deferred credits” on our consolidated balance sheet as of December 31, 2017.

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 and $34 million of other components of net benefit credits (excluding the service cost component) from “General and administrative” to “Other, net” in our accompanying consolidated statements of income for the years ended December 31, 2017 and 2016, respectively. We prospectively applied Topic 715 related to net benefit costs eligible for capitalization.

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 “Retained deficit” on our consolidated statement of stockholders’ equity for the year ended December 31, 2018.

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.

Restricted deposits were $51 million and $62 million as of December 31, 2018 and 2017, respectively.

Accounts Receivable, net

The amounts reported as “Accounts receivable, net” on our accompanying consolidated balance sheets as of December 31, 2018 and 2017 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 $3 million and $35 million as of December 31, 2018 and 2017, 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 CO_2 is injected into certain producing oil reservoirs. In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs.

A 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. In those 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.

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 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 Excess Investment Cost

We account for investments which we do not control, but do have the ability to exercise significant influence using the equity method of accounting. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee’s net income and by contributions made, and decreased by our proportionate share of the investee’s net losses and by distributions received.

With regard to our equity investments in unconsolidated affiliates, in almost all cases, either (i) the price we paid to acquire our share of the net assets of such equity investees or (ii) the revaluation of our share of the net assets of any retained noncontrolling equity investment (from the sale of a portion of our ownership interest in a consolidated subsidiary, thereby losing our controlling financial interest in the subsidiary) differed from the underlying carrying value of such net assets. This differential consists of two pieces. First, an amount related to the difference between the investee’s recognized net assets at book value and at current fair values (representing the appreciated value in plant and other net assets), and secondly, to any premium in excess of fair value (referred to as equity method goodwill) we paid to acquire the investment. We include both amounts within “Investments” on our accompanying consolidated balance sheets.

The first differential, representing the excess of the fair market value of our investees' plant and other net assets over its underlying book value at either the date of acquisition or the date of the loss of control totaled $470 million and $732 million as of December 31, 2018 and 2017, respectively. Generally, this basis difference relates to our share of the underlying depreciable assets, and, as such, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2018, this excess investment cost is being amortized over a weighted average life of approximately twelve years.

The second differential, representing equity method goodwill, totaled $1,967 million for both periods as of December 31, 2018 and 2017. This differential is not subject to amortization but rather to impairment testing as part of our periodic evaluation of the recoverability of our investment as compared to the fair value of net assets accounted for under the equity method. Our impairment test considers whether the fair value of the equity investment as a whole has declined and whether that decline is other than temporary.

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) CO_2; (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, 2018 and 2017, the gross carrying amounts of these intangible assets was $4,305 million and the accumulated amortization was $1,425 million and $1,206 million, respectively, resulting in net carrying amounts of $2,880 million and $3,099 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, 2018, 2017 and 2016, the amortization expense on our intangibles totaled $219 million, $220 million and $223 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2019 – 2023) is approximately $213 million, $209 million, $209 million, $207 million, and $203 million, respectively. As of December 31, 2018, the weighted average amortization period for our intangible assets was approximately fifteen years.

Revenue Recognition

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with Accounting Standards Updates 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, CO_2 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 16 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 of energy commodities sold, including natural gas, NGL and other refined petroleum products, adjusted for the effects of our energy commodity activities, as applicable, other than production from our CO_2 business segment.

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 oil, gas and CO_2 producing activities included within operations and maintenance totaled $363 million, $342 million and $349 million for the years ended December 31, 2018, 2017 and 2016, 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. 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. 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.

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 sheet. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—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.

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

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. We translate 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 are translated at weighted-average rates of exchange prevailing during the year and stockholders' equity accounts are translated by using historical exchange rates. The cumulative translation adjustments balance is 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 natural gas, NGL and crude oil. 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 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, and how any ineffectiveness will be measured and recorded. If we designate a derivative contract as a cash flow accounting hedge, the effective portion of the change in fair value of the derivative is deferred in "Accumulated other comprehensive loss" and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value or amount excluded from the assessment of hedge effectiveness is recognized currently in earnings. If we designate a derivative contract as a fair value accounting hedge, the effective portion of the change in fair value of the derivative is recorded as an adjustment to the item being hedged. Any ineffective portion of the derivative's change in fair value is recognized currently in earnings. If we designate a derivative contract as a net investment accounting hedge, the effective portion of the change in fair value of the derivative is reflected in the Cumulative Translation Adjustment (CTA) section of Other Comprehensive Income (OCI) 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.

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 refunded to customers through the ratemaking process. 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, 2018 and 2017 (in millions):

	December 31,	
	2018	2017
Current regulatory assets	$66	$60
Non-current regulatory assets	245	288
Total regulatory assets(a)	$311	$348
Current regulatory liabilities	$29	$107
Non-current regulatory liabilities	206	236
Total regulatory liabilities(b)	$235	$343

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(a) Regulatory assets as of December 31, 2018 include (i) $176 million of unamortized losses on disposal of assets; (ii) $53 million income tax gross up on equity AFUDC; and (iii) $82 million of other assets including amounts related to fuel tracker arrangements. Approximately $98 million of the regulatory assets, with a weighted average remaining recovery period of 23 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, 2018 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 $136 million of the $206 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 18 years, while the remaining $70 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,		
	2018	2017	2016
Net Income Available to Common Stockholders	$1,481	$27	$552
Participating securities:			

Less: Net Income Allocated to Restricted stock awards(a)	(8)	(5)	(4)
Net Income Allocated to Class P Stockholders	$1,473	$22	$548
Basic Weighted Average Common Shares Outstanding	2,216	2,230	2,230
Basic Earnings Per Common Share	$0.66	$0.01	$0.25

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(a) As of December 31, 2018, there were approximately 13 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,		
	2018	2017	2016
Unvested restricted stock awards	12	10	8
Warrants to purchase our Class P shares(a)		116	293
Convertible trust preferred securities	3	3	8
Mandatory convertible preferred stock(b)	48	58	58

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(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 KMI 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 and Acquisition

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 and Kinder Morgan Canada Inc., the Canadian employer of our staff that operate the business, which were indirectly acquired by the Government of Canada through Trans Mountain Corporation (a subsidiary of the Canada Development Investment Corporation) for 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 $596 million within “Loss on impairments and divestitures, net” in our accompanying consolidated statement of income during the year ended December 31, 2018, including an incremental working capital adjustment of $26 million accrued as of December 31, 2018.

On January 3, 2019, pursuant to KML’s shareholders’ approval on November 29, 2018, KML distributed to its shareholders as a return of capital, the net proceeds from the TMPL Sale, after capital gains taxes, customary purchase price adjustments and the repayment of debt outstanding under a temporary KML credit facility (see Note 9, “Debt—Credit Facilities and Restrictive Covenants—KML”). KML’s public owners of its restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and part of our approximate 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to immediately 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. To facilitate the return of capital and provide flexibility for KML’s dividends going forward, KML’s shareholders also approved a reduction in the stated capital of its restricted voting shares by C$1.45 billion, which was recorded in the fourth quarter of 2018, along with a “reverse stock split” of KML’s restricted voting shares, and KML’s special voting shares that we own, on a one-for-three basis (three shares consolidating to one share) which occurred on January 4, 2019.

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 (US$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 holds our Canadian business while we retained the remaining 70% interest. We used the proceeds from KML's IPO to pay down debt.

Subsequent to the IPO, we retained control of KML and the limited partnership, and as a result, they remain consolidated in our consolidated financial statements. The public ownership of the KML restricted voting shares is reflected within "Noncontrolling interests" in our consolidated statements of stockholders' equity and consolidated balance sheets. Earnings attributable to the public ownership of KML are presented in "Net income attributable to noncontrolling interests" in our consolidated statements of income for the periods presented after May 30, 2017.

The net proceeds received of $1,245 million are presented as "Contributions from noncontrolling interests - net proceeds from KML IPO" on our consolidated statement of cash flows for the year ended December 31, 2017. Because we retained control of KML subsequent to the IPO, the $314 million adjustment made to "Additional paid-in capital" on our consolidated statement of stockholders equity for the year ended December 31, 2017 represents the difference between our book value prior

to the sale and our share of book value in KML's net assets after the sale. The impact of the IPO resulted in a $166 million deferred income tax adjustment. At the date of the IPO, $765 million was attributed to the KML public shareholders to reflect their proportionate ownership percentage in the net assets of KML acquired from us and is included in "Noncontrolling interests" on our consolidated statement of stockholders equity. The above amounts recorded to "Additional paid-in capital" and "Noncontrolling interests" are net of IPO fees.
In addition, the amount recorded to "Noncontrolling interests" at the date of the IPO was reduced by $81 million primarily associated with the allocation of currency translation adjustments from "Accumulated other comprehensive loss" to "Noncontrolling interests."
The portion of the Canadian business operations that we sold to the public on May 30, 2017 represented Canadian assets that were included in our Kinder Morgan Canada, Terminals and Product Pipelines business segments and include (i) the Trans Mountain pipeline system; (ii) the Canadian Cochin pipeline system; (iii) the Puget Sound pipeline system; (iv) the Jet Fuel pipeline system; and (v) terminal facilities located in Western Canada. In January 2018, KML completed the registration of its restricted voting shares pursuant to Section 12(g) of the United States Securities Exchange Act of 1934 (the "Exchange Act") and subsequently is subject to the reporting requirements of Section 13(a) of the Exchange Act.

In conjunction with the IPO, Kinder Morgan Canada Limited Partnership (KMC LP) and Kinder Morgan Canada GP Inc. (KMC GP) were formed to hold our Canadian business. We have determined that KMC LP is a variable interest entity because a simple majority or lower threshold of the limited partnership interests do not possess substantive "kick-out rights" (i.e., the right to remove the general partner or to dissolve (liquidate) the entity without cause) or substantive participation rights. We have also determined KMC GP is the primary beneficiary because it has the power to direct the activities that most significantly impact KMC LP's performance, the right to receive benefits and the obligation to absorb losses, that could be significant to KMC LP. As a result, KMC GP consolidates KMC LP. KMC GP is a wholly owned subsidiary of KML, which is indirectly controlled by us through our 100% interest in KML's special voting shares that represent approximately 70% of KML's total voting shares (comprised of restricted voting shares and special voting shares). Consequently, we consolidate KML and the variable interest entity, KMC LP, in our consolidated financial statements.

The following table shows the carrying amount and classification of KMC LP's assets and liabilities in our consolidated balance sheet (in millions):

	December 31,	
	2018	2017
Assets		
Total current assets	$3,204	$270
Property, plant and equipment, net	719	2,956
Total goodwill, deferred charges and other assets	8	322
Total assets	$3,931	$3,548
Liabilities		
Current portion of debt	$—	$—
Total other current liabilities	2,353	236
Long-term debt, excluding current maturities	—	—
Total other long-term liabilities and deferred credits	52	414
Total liabilities	$2,405	$650

We receive distributions from KMC LP through our indirectly owned limited partnership interests in KMC LP, but otherwise the assets of KMC LP cannot be used to settle our obligations other than those of KML. We do not guarantee the debt, commercial paper or other similar commitments of KMC LP or any of its subsidiaries, and the obligations of KMC LP may only be settled using the assets of KMC LP. KMC LP does not guarantee the debt or other similar commitments of KMI.

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, have been reflected as of December 31, 2018 within “Redeemable Noncontrolling Interest” and as of December 31, 2017, as a deferred credit within “Other long-term liabilities and deferred credits” on our consolidated balance sheets. Once these contingencies expire, EIG’s capital account will be reflected in Noncontrolling interests on our consolidated balance sheet.

Terminals Asset Sale

In October 2016, we entered into a definitive agreement to sell several bulk terminals to an affiliate of Watco Companies, LLC for approximately $100 million. The terminals are predominantly located along the inland river system and handle mostly coal and steel products, and are included within our Terminals business segment. The sale of eight of the locations closed in the fourth quarter of 2016, for which we received $37 million of the total consideration, and the balance of this transaction, which included an additional eleven locations, closed in the second quarter of 2017 as certain conditions were satisfied. As a result of this transaction, we recognized a pre-tax loss of $81 million, including a $7 million reduction of goodwill, which is included within “Loss on impairments and divestitures, net” on our accompanying consolidated statement of income for the year ended December 31, 2016.

Sale of Equity Interest in SNG

On September 1, 2016, we completed the sale of a 50% interest in our SNG natural gas pipeline system to The Southern Company (Southern Company), receiving proceeds of $1.4 billion, and the formation of a joint venture, which includes our remaining 50% interest in SNG. We used the proceeds from the sale to reduce outstanding debt. We recognized a pre-tax loss of $84 million on the sale of our interest in SNG which is included within “Loss on impairments and divestitures, net” on the accompanying consolidated statement of income for the year ended December 31, 2016. As a result of this transaction, we no longer hold a controlling interest in SNG or Bear Creek Storage Company, LLC (Bear Creek) (50% of which is owned by SNG) and, as such, we now account for our remaining equity interests in SNG and Bear Creek as equity investments.

Acquisition of BP Products North America Inc. (BP) Terminal Assets

On February 1, 2016, we completed the acquisition of 15 products terminals and associated infrastructure from BP for $349 million, including a transaction deposit paid in 2015 and working capital adjustments paid in 2016. The purchase price consisted of $396 million of property, plant and equipment, $2 million of current assets, and assumed liabilities of $49 million. In conjunction with this transaction, we and BP formed a joint venture with an equity ownership interest of 75% and 25%, respectively. Subsequent to the acquisition, we contributed 14 of the acquired terminals to the joint venture, which we operate, and the remaining terminal is solely owned by us. BP acquired its 25% interest in the joint venture for $84 million, which we reported as “Contributions from noncontrolling interests - other” within our accompanying consolidated statement of cash flows for the year ended December 31, 2016. These terminals are included in our Terminals and Products Pipelines business segments.

4. Impairments and Losses (Gains) on Divestitures

During the years ended December 31, 2018, 2017, and 2016, we recorded impairments of certain equity investments, long-lived assets, and intangible assets, and net gains and losses on divestitures totaling $437 million, $172 million, and $1,013 million, respectively. During 2016, and to a lesser degree in 2017 and 2018, a sustained lower commodity price environment, and negative outlook for certain long-term transportation contracts, led us to cancel certain construction projects, divest of certain assets, write-down certain assets and investments to fair value.

These impairments were driven by market conditions that existed at the time and required management to estimate the fair value of these 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.

In January 2019, Pacific Gas and Electric (PG&E) filed for Chapter 11 bankruptcy protection. Our exposure to PG&E is limited to our $750 million equity investment in Ruby and an approximate $55 million note receivable from Ruby, where PG&E is Ruby's largest customer. PG&E represents approximately $93 million of annual revenues on Ruby, and our partner's preferred equity interest in Ruby is senior to our interest. Despite the bankruptcy filing, Ruby continues to perform under its existing service contracts with PG&E and PG&E has provided credit support on its trade payables to Ruby through a prepayment arrangement. While the ultimate outcome of the bankruptcy proceedings remains uncertain, there is the potential for Ruby's existing contracts with PG&E to be canceled in the bankruptcy process. Any cancellation of these contracts could negatively impact Ruby's future revenues and require us to evaluate our investment in Ruby for an other than temporary impairment. This could result in a material impairment of our investment in Ruby at the time such events become known.

We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill. Because certain assets and investments have been written down to fair value in the last few years, any deterioration in fair value relative to our carrying value increases the likelihood of further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to be not fully recoverable.

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

	Year Ended December 31,		
	2018	2017	2016
Natural Gas Pipelines			
Impairments of long-lived assets(a)	$600	$30	$106
(Gains) losses on divestitures of long-lived assets(b)	(6)	—	94
Impairment of equity investments(c)	270	150	606
Impairment at equity investee(d)	—	10	7
Products Pipelines			
Impairments of long-lived assets(e)	36	—	66
Losses on divestitures of long-lived assets	—	—	10
Gain on divestiture of equity investment	—	—	(12)
Terminals			
Impairments of long-lived assets(f)	59	3	19
(Gains) losses on divestitures of long-lived assets(g)	(6)	(18)	80
Losses on impairments and divestitures of equity investments, net	—	—	16
CO_2			
Impairments of long-lived assets(h)	79	(1)	20
Gain on divestitures of long-lived assets	—	—	(1)
Impairment at equity investee	—	(4)	9
Kinder Morgan Canada			
Gain on divestiture of long-lived assets(i)	(595)	—	—
Other losses (gains) on divestitures of long-lived assets	—	2	(7)
Pre-tax losses on impairments and divestitures, net	$437	$172	$1,013

(a) 2018 amount represents the non-cash impairment associated with certain gathering and processing assets in Oklahoma. 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. 2016 amount represents the project write-off of our portion of the Northeast Energy Direct Market project.
(b) 2016 amount primarily relates to our sale of a 50% interest in SNG.
(c) 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. 2016 amount includes a $350 million non-cash impairment of our investment in MEP and a $250 million non-cash impairment of our investment in Ruby.
(d) 2017 and 2016 amounts represent losses on impairments recorded by equity investees and are included in “Earnings from equity investments” on our accompanying consolidated statements of income.
(e) 2018 amount represents a project write-off associated with the Utica Marcellus Texas pipeline. 2016 amount represents project write-offs associated with the canceled Palmetto project.

(f) 2018 amount primarily relates to non-cash impairments of certain Northeast terminal assets.
(g) 2017 amount includes a $23 million gain related to the sale of a 40% membership interest in the Deeprock Development joint venture. 2016 amount primarily relates to the sale of 20 bulk terminals that handle mostly coal and steel products, predominately located along the inland river system.
(h) 2018 amount represents impairments of oil and gas properties.
(i) 2018 amount represents the gain on the TMPL Sale.

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. These reduced estimates triggered an impairment analysis 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,		
	2018	2017	2016
U.S.	$ 1,739	$ 1,976	$ 1,466
Foreign	767	185	172
Total Income Before Income Taxes	$ 2,506	$ 2,161	$ 1,638

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

	Year Ended December 31,		
	2018	2017	2016
Current tax expense (benefit)			
Federal	$ (22)	$ (137)	$ (148)
State	(45)	(16)	(28)
Foreign	249	18	6
Total	182	(135)	(170)
Deferred tax expense (benefit)			
Federal	425	2,022	998
State	55	4	51
Foreign	(75)	47	38
Total	405	2,073	1,087
Total tax provision	$ 587	$ 1,938	$ 917

We are subject to taxation in Canada and Mexico. In Canada we recognized income tax expense of $168 million, $58 million and $38 million at December 31, 2018, 2017, and 2016, respectively. In Mexico we recognized income tax expense of $6 million, $7 million and $6 million at December 31, 2018, 2017, and 2016, 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,					
	2018		2017		2016	
Federal income tax	$526	21.0 %	$756	35.0 %	$573	35.0 %
Increase (decrease) as a result of:						
State deferred tax rate change	(7)	(0.3)%	10	0.5 %	11	0.7 %
Taxes on foreign earnings, net of federal benefit	131	5.2 %	42	1.9 %	28	1.7 %
Net effects of noncontrolling interests	(65)	(2.6)%	(14)	(0.7)%	(4)	(0.3)%
State income tax, net of federal benefit	46	1.8 %	38	1.8 %	26	1.6 %
Dividend received deduction	(31)	(1.2)%	(56)	(2.6)%	(48)	(2.9)%
Adjustments to uncertain tax positions	(47)	(1.9)%	(12)	(0.6)%	(23)	(1.4)%
Valuation allowance on investment and tax credits	14	0.5 %	13	0.6 %	34	2.1 %
Impact of the 2017 Tax Reform	—	— %	1,240	57.4 %	—	— %
Nondeductible goodwill	58	2.3 %	—	— %	301	18.5 %
General business credit	(64)	(2.6)%	(95)	(4.4)%	—	— %
Other	26	1.2 %	16	0.8 %	19	1.1 %
Total	$587	23.4 %	$1,938	89.7 %	$917	56.1 %

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

	December 31,	
	2018	2017
Deferred tax assets		
Employee benefits	$238	$251
Accrued expenses	76	73
Net operating loss, capital loss and tax credit carryforwards	1,526	1,113
Derivative instruments and interest rate and currency swaps	9	12
Debt fair value adjustment	33	37
Investments	177	968
Other	—	6
Valuation allowances	(178)	(171)
Total deferred tax assets	1,881	2,289
Deferred tax liabilities		
Property, plant and equipment	270	225
Other	45	20
Total deferred tax liabilities	315	245
Net deferred tax assets	$1,566	$2,044

Deferred Tax Assets and Valuation Allowances: The step-up in tax basis from the merger transactions that occurred in November 2014 resulted in a deferred tax asset, primarily related to our investment in KMP. As book earnings from our investment in KMP are projected to exceed taxable income (primarily as a result of the partnership's tax depreciation in excess of book depreciation), the deferred tax asset related to our investment in KMP is expected to be fully realized.

We increased our valuation allowances in 2018 by $7 million, primarily due to a $17 million increase for capital loss carryover as a result of the TMPL Sale, a $6 million decrease for foreign operating losses and a $4 million utilization of foreign tax credits.

We have 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 at December 31, 2018. As of December 31, 2017, we had deferred tax assets of $935 million related to net operating loss carryovers, $178 million related to general business, alternative minimum and foreign tax credits and $133 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 2022.

Our alternative minimum tax credit carryforwards decreased by $8 million in 2018 as a result of a federal audit settlement. In 2017, our decision to elect to forgo bonus depreciation on property placed in service in that year allowed us to utilize $137 million of minimum tax credits. Section 168(k)(4) of the Internal Revenue Code allows for corporate taxpayers with minimum tax credit carryforwards to forgo bonus depreciation and accelerate their use of the credits to reduce tax liability in that same tax year if the amount of the allowable credit exceeds the taxpayer’s tax liability. We received an income tax refund of $145 million in 2018 related to the 2017 credit utilization and 2018 audit settlement.

Expiration Periods for Deferred Tax Assets: As of December 31, 2018, we have U.S. federal net operating loss carryforwards of $1.4 billion that will be carried forward indefinitely and $3.4 billion that will expire from 2019 - 2037; state losses of $3.7 billion which will expire from 2019 - 2038; and foreign losses of $112 million which will expire from 2029 - 2038. We also have $241 million of general business credits which will expire from 2019 - 2028; a capital loss carryover of $17 million which will expire in 2023; and approximately $17 million of foreign tax credits, which will expire from 2020 - 2023. Use of a portion of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations. If certain substantial changes in our ownership occur, there would be an annual limitation on the amount of carryforwards that could be utilized.

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

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

	Year Ended December 31,		
	2018	2017	2016
Balance at beginning of period	$97	$122	$148
Additions based on current year tax positions	3	3	3
Additions based on prior year tax positions	7	—	7
Reductions based on prior year tax positions	—	—	(1)
Reductions based on settlements with taxing authority	(73)	(22)	(26)
Reductions due to lapse in statute of limitations	—	(2)	(9)
Impact of the 2017 Tax Reform	—	(4)	—
Balance at end of period	$34	$97	$122

We recognize interest and/or penalties related to income tax matters in income tax expense. We recognized tax benefits of $15 million, $9 million and an expense of $2 million at December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, 2017 and 2016, we had $2 million, $19 million and $28 million, respectively, of accrued interest. We had less than $1 million of accrued penalties as of December 31, 2018 and no accrued penalties as of December 31, 2017. All of the $34 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 decrease by approximately $21 million during the next year to approximately $13 million, primarily due to settlements with taxing authorities, partially offset by additions for state filing positions taken in prior years.

We are subject to taxation, and have tax years open to examination for the periods 2015-2017 in the U.S., 2005-2017 in various states and 2007-2017 in various foreign jurisdictions.

Impact of 2017 Tax Reform

On December 22, 2017, the U.S. enacted the 2017 Tax Reform. Among the many provisions included in the 2017 Tax Reform is a provision to reduce the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

As of December 31, 2017, we had 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. Prior to the 2017 Tax Reform, the value of these deferred tax assets was recorded at the previous income tax rate of 35%, which represented their expected future benefit to us. As a result of the 2017 Tax Reform, the future benefit of these deferred tax assets was re-measured at the new income tax rate of 21% and we recorded an approximate $1,240 million provisional non-cash adjustment for the year ended December 31, 2017. We determined the effects of the rate change using our best estimate of temporary book-to-tax differences. Upon final analysis and remeasurement of our deferred tax balances, the December 31, 2017 adjustment recorded accurately reflected the change in corporate income tax rates and has not been materially adjusted in subsequent periods.

In addition, the 2017 Tax Reform required a mandatory deemed repatriation of post-1986 undistributed foreign earnings and profits. As of December 31, 2017, we recorded a provisional amount for this 2017 Tax Reform provision and as of December 31, 2018, completed our analysis on this provision. The 2017 Tax Reform transition tax was $2 million.

The income tax rate change in the 2017 Tax Reform had an impact not only on our corporate income taxes but also resulted in us recording an approximate $144 million after-tax ($219 million pre-tax) provisional non-cash adjustment, including our share of equity investee provisional adjustments, related to our FERC regulated business for the year ended December 31, 2017. As a result of the completion of our assessment of the 2017 Tax Reform’s effect on our FERC regulated business, we decreased this non-cash provisional adjustment by approximately $27 million after-tax ($36 million pre-tax) during the year ended December 31, 2018.

The 2017 Tax Reform requires a U.S. corporation to record taxes on global intangible low-tax income (GILTI) and elect an accounting policy to either recognize GILTI as a current period expense when incurred or to record deferred taxes for the temporary basis differences expected to reverse in the future as GILTI. Though we did not generate any GILTI during 2018, we have elected to recognize the GILTI tax as a period cost in the future, as applicable.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2018 and 2017, our property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2018	2017
Pipelines (Natural gas, liquids, crude oil and CO_2)	$19,727	$20,157
Equipment (Natural gas, liquids, crude oil, CO_2, and terminals)	24,392	24,152
Other(a)	5,447	5,570
Accumulated depreciation, depletion and amortization	(15,359)	(14,175)
	34,207	35,704
Land and land rights-of-way	1,378	1,456
Construction work in process	2,312	2,995

Property, plant and equipment, net	$37,897	$40,155

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(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, 2018 and 2017, property, plant and equipment, net included $12,349 million and $14,055 million, respectively, of assets which were regulated by either the FERC or the NEB. Depreciation, depletion, and amortization expense

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charged against property, plant and equipment was $2,057 million, $2,022 million, and $1,970 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Asset Retirement Obligations

As of December 31, 2018 and 2017, we recognized asset retirement obligations in the aggregate amount of $213 million and $208 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. As of December 31, 2018 and 2017, our investments consisted of the following (in millions):

	December 31,	
	2018	2017
Citrus Corporation	$1,708	$1,698
SNG	1,536	1,495
Ruby	750	774
NGPL Holdings LLC	733	687
Gulf LNG Holdings Group, LLC	361	461
Plantation Pipe Line Company	344	331
Utopia Holding LLC	333	276
EagleHawk	299	314
Gulf Coast Express Pipeline LLC	240	—
MEP	235	253
Red Cedar Gathering Company	191	187
Watco Companies, LLC	185	182
Double Eagle Pipeline LLC	140	149
Liberty Pipeline Group LLC	66	71
Bear Creek Storage	65	63
Sierrita Gas Pipeline LLC	55	55
Permian Highway Pipeline	45	—
FEP	44	112
All others	151	190
Total investments	$7,481	$7,298

As shown in the investment balance table above and the earnings from equity investments table below, our significant equity investments, as of December 31, 2018 consisted of the following:

- Citrus Corporation—We own a 50% interest in Citrus Corporation, the sole owner of Florida Gas Transmission Company, L.L.C. (Florida Gas). Florida Gas transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,300-mile natural gas pipeline. Energy Transfer Partners L.P. operates Florida Gas and owns the remaining 50% interest in Citrus;
- SNG—We operate SNG and own a 50% interest in SNG; and Evergreen Enterprise Holdings, LLC, a subsidiary of Southern Company, owns the remaining 50% interest;
- Ruby—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;

- NGPL Holdings LLC— We operate NGPL Holdings LLC and own a 50% interest in NGPL Holdings LLC, the indirect owner of NGPL and certain affiliates, collectively referred to in this report as NGPL, a major interstate natural gas pipeline and storage system. The remaining 50% interest is owned by Brookfield;
- Gulf LNG Holdings Group, LLC—We operate Gulf LNG Holdings Group, LLC and own a 50% interest in Gulf LNG Holdings Group, LLC, the owner of a LNG receiving, storage and regasification terminal near Pascagoula, Mississippi, as well as pipeline facilities to deliver vaporized natural gas into third party pipelines for delivery into various markets around the country. The remaining 50% interest is owned by a variety of investment entities, including subsidiaries of The Blackstone Group, LP; Warburg Pincus, LLC; Kelso and Company; and Chatham Asset Management, LLC, which is directed by Chatham Asset GP, LLC;
- Plantation—We operate Plantation and own a 51.17% interest in Plantation, the sole owner of the Plantation refined petroleum products pipeline system. A subsidiary of Exxon Mobil Corporation owns the remaining interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered substantive participating rights; therefore, we do not control Plantation, and account for the investment under the equity method;
- Utopia Holding L.L.C. — We operate Utopia Holding L.L.C. and own a 50% interest in Utopia Holding L.L.C. Riverstone Investment Group LLC owns the remaining 50% interest;
- BHP Billiton Petroleum (Eagle Ford Gathering) LLC, (EagleHawk)—We own a 25% interest in EagleHawk, the sole owner of natural gas and condensate gathering systems serving the producers of the Eagle Ford shale formation. A subsidiary of BHP Billiton Petroleum (Tx Gathering), LLC operates EagleHawk and owns the remaining 75% ownership interest;
- Gulf Coast Express Pipeline LLC — We operate Gulf Coast Express Pipeline LLC and own 35% interest of Gulf Coast Express Pipeline LLC indirectly through Kinder Morgan Texas Pipeline LLC, our 100% subsidiary. DCP GCX Pipeline LLC, an indirect subsidiary of DCP Midstream, owns 25% interest; Targa GCX Pipeline LLC, an indirect subsidiary of Targa Resources Corp., owns 25% interest and Altus Midstream Company, an indirect subsidiary of Apache Corporation, owns 15% interest;
- MEP—We operate MEP and own a 50% interest in MEP, the sole owner of the MEP natural gas pipeline system. The remaining 50% ownership interest is owned by subsidiaries of Energy Transfer Partners L.P.;
- Red Cedar Gathering Company—We own a 49% interest in Red Cedar Gathering Company, the sole owner of the Red Cedar natural gas gathering, compression and treating system. The Southern Ute Indian Tribe owns the remaining 51% interest and serves as operator of Red Cedar;
- Watco Companies, LLC—We hold a preferred and common equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the U.S. 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, and participate partially in additional profit distributions at a rate equal to 0.4%. 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 3.2% common ownership;
- Double Eagle Pipeline LLC - We own a 50% equity interest in Double Eagle Pipeline LLC. The remaining 50% interest is owned by Magellan Midstream Partners;
- Liberty Pipeline Group, LLC (Liberty) —We own a 50% interest in Liberty. ETC NGL Transport, LLC, a subsidiary of Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of Liberty;
- Bear Creek Storage—We own a combined 75% interest in Bear Creek through: our wholly owned subsidiary's (TGP) 50% interest and an additional 25% indirect interest through our 50% equity interest in SNG, which owns the remaining 50% interest;
- Sierrita Gas Pipeline LLC — We operate Sierrita Gas Pipeline LLC and own a 35% interest in Sierrita Gas Pipeline LLC. MGI Enterprises U.S. LLC, a subsidiary of PEMEX, owns 35%; and MIT Pipeline Investment Americas, Inc., a subsidiary of Mitsui & Co., Ltd, owns 30%;
- Permian Highway Pipeline — We operate Permian Highway Pipeline and own a 50% interest of Permian Highway Pipeline indirectly through KMTP, our wholly owned subsidiary. BCP PHP, LLC (BCP), a portfolio company of

Blackstone Energy Partners, owns the remaining 50% interest. An affiliate of an anchor shipper exercised its option in January 2019 to acquire a 20% equity interest in the project, bringing KMTP's and BCP's ownership interest to 40% each. Altus Midstream Company (Altus Midstream) (a gas gathering, processing and transportation company formed by shipper Apache Corporation) has an option to acquire an equity interest in the project from the initial partners by September 2019. If Altus Midstream exercises its option, KMTP, BCP and Altus Midstream will each hold a 26.67% ownership interest in the project. KMTP will build and operate the pipeline;

- FEP —We own a 50% interest in FEP, the sole owner of the Fayetteville Express natural gas pipeline system. Energy Transfer Partners, L.P. owns the remaining 50% interest and serves as operator of FEP;
- Cortez Pipeline Company—We operate the Cortez CO_2 pipeline system, and own a 52.98% interest in the Cortez Pipeline Company, the sole owner of the Cortez CO_2 pipeline system. Mobil Cortez Pipeline Inc. owns 33.25%; and Cortez Vickers Pipeline Company owns the remaining 13.77%.

Our earnings from equity investments were as follows (in millions):

	Year Ended December 31,		
	2018	2017	2016
Gulf LNG Holdings Group, LLC(a)	$ 209	$ 47	$ 48
Citrus Corporation	169	108	102
SNG	141	77	58
NGPL Holdings LLC	66	10	12
FEP	55	53	51
Plantation Pipe Line Company	55	46	37
Cortez Pipeline Company(b)	36	44	24
MEP	31	38	40
Ruby	26	44	15
Watco Companies, LLC	21	19	25
Red Cedar Gathering Company(c)	18	14	24
Utopia Holding LLC	14	—	—
Double Eagle Pipeline LLC	10	7	5
Bear Creek Storage	9	8	2
EagleHawk	7	24	10
Liberty Pipeline Group LLC	7	9	11
Sierrita Gas Pipeline LLC	7	7	7
Gulf Coast Express LLC	2	—	—
All others	4	23	26
Total earnings from equity investments	$ 887	$ 578	$ 497
Amortization of excess costs	(95)	(61)	(59)

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(a) 2018 amount includes our share of earnings recognized due to a ruling by an arbitration panel affecting a customer contract.

(b) 2017 and 2016 amounts include $(4) million and $9 million, respectively, representing our share of a non-cash impairment charge (pre-tax) recorded by Cortez Pipeline Company.

(c) 2017 amount includes non-cash impairment charges of $10 million (pre-tax) related to our investment.

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):

	Year Ended December 31,		
Income Statement	2018	2017	2016
Revenues	$ 5,129	$ 4,703	$ 4,084
Costs and expenses	3,371	3,398	3,056
Net income	$ 1,758	$ 1,305	$ 1,028

	December 31,	
Balance Sheet	2018	2017
Current assets	$ 1,496	$ 956
Non-current assets	23,396	22,344
Current liabilities	2,715	1,241
Non-current liabilities	9,555	10,605
Partners'/owners' equity	12,622	11,454

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2018 and 2017 are summarized by reporting unit as follows (in millions):

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO2	Products Pipelines	Products Pipelines Terminals	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	$ 15,892	$ 5,812	$ 1,528	$ 2,125	$ 221	$ 1,575	$ 562	$ 27,715
Accumulated impairment losses	(1,643)	(1,597)	—	(1,197)	(70)	(679)	(377)	(5,563)
December 31, 2016	14,249	4,215	1,528	928	151	896	185	22,152
Currency translation	—	—	—	—	—	—	13	13
Divestitures(a)	—	—	—	—	—	(3)	—	(3)
December 31, 2017	14,249	4,215	1,528	928	151	893	198	22,162
Currency translation	—	—	—	—	—	—	(8)	(8)
Divestitures(b)	—	—	—	—	—	—	(190)	(190)
Other	—	—	—	—	—	1	—	1
December 31, 2018	$ 14,249	$ 4,215	$ 1,528	$ 928	$ 151	$ 894	$ —	$ 21,965

(a) 2017 includes $3 million related to certain terminal divestitures.
(b) 2018 includes $190 million related to the TMPL Sale.

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

We determine the fair value of each reporting unit as of May 31 of each year based primarily on a market approach utilizing enterprise value to estimated earning before interest, taxes, depreciation and amortization (EBITDA) multiples of comparable companies. The value of each reporting unit is determined on a stand-alone basis 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, 2018 annual test included a discounted cash flow analysis (income approach) to evaluate the fair value of this reporting unit to provide 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 for this reporting unit to arrive at an estimated fair value of this reporting unit giving more weighting on the income approach and less on the market approach as we believed the value indicated using the income approach is more representative of the value that could be received from a market participant. As of May 31, 2018, each of our reporting units indicated a fair value in excess of their respective carrying values (by at least 10%) and step 2 was not required. The results of our Step 1 analysis did not indicate an impairment of goodwill and we did not identify any triggers for further impairment analysis during the remainder of the year.

A continued period of volatile commodity prices could result in deterioration of market multiples, comparable sales transactions prices, weighted average costs of capital, and our cash flow estimates. 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 potentially resulting in future impairments of long-lived assets, equity method investments, and/or goodwill. Such non-cash impairments could have a significant effect on our results of operations.

9. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our accompanying consolidated statements of income.

The following table provides detail on the principal amount of our outstanding debt balances. The table amounts exclude all debt fair value adjustments, including debt discounts, premiums and issuance costs (in millions):

	December 31,	
	2018	2017
Credit facility and commercial paper borrowings(a)	$433	$365
Corporate senior notes(b)		
6.00%, due January 2018	—	750
7.00%, due February 2018	—	82
5.95%, due February 2018	—	975
7.25%, due June 2018	—	477
9.00%, due February 2019	500	500
2.65%, due February 2019	800	800
3.05%, due December 2019	1,500	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)	860	900
3.95%, due September 2022	1,000	1,000
3.15%, due January 2023	1,000	1,000
Floating rate, due January 2023	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)	573	600
6.67%, due November 2027	7	7
4.30%, due March 2028	1,250	—
7.25%, due March 2028	32	32
6.95%, due June 2028	31	31
8.05%, due October 2030	234	234
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

	December 31, 2018	December 31, 2017
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	—
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 December 2035	409	421
Trust I Preferred Securities, 4.75%, due March 2028(d)	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(e)	100	100
Other miscellaneous debt(f)	250	278
Total debt – KMI and Subsidiaries	36,593	36,916
Less: Current portion of debt(g)	3,388	2,828
Total long-term debt – KMI and Subsidiaries(h)	$33,205	$34,088

(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, 2018 exchange rate of 1.1467 U.S. dollars per Euro and at the December 31, 2017 exchange rate of 1.2005 U.S. dollars per Euro. As of December 31, 2018 and 2017, the cumulative changes in the exchange rate of U.S. dollars per Euro since issuance had resulted in increases to our debt balance of $46 million and $86 million, respectively, related to the 1.50% series and increases of $30 million and $57 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 cross-currency swap agreements 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) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2018, 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%, carry a liquidation value of $50 per security plus accrued and unpaid distributions. The Trust I Preferred Securities outstanding as of December 31, 2018 are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; and (ii) $25.18 in cash without interest. We have the right to redeem these Trust I Preferred Securities at any time.

(e) As of December 31, 2018 and 2017, KMGP had outstanding, 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057. Since August 18, 2012, dividends on the preferred stock accumulate at a floating rate of the 3-month LIBOR plus 3.8975% and are payable quarterly in arrears, when and if declared by KMGP's board of directors, on February 18, May 18, August 18 and November 18 of each year, beginning November 18, 2012. The preferred stock has approval rights over a commencement of or filing of voluntary bankruptcy by KMP or its SFPP or Calnev subsidiaries.

(f) Includes capital lease obligations with monthly installments. The lease terms expire between 2024 and 2061.

(g) Amounts include KMI and KML outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months. See "—Current Portion of Debt" below.

(h) Excludes our "Debt fair value adjustments" which, as of December 31, 2018 and 2017, increased our combined debt balances by $731 million and $927 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,	
	2018	2017
$500 million, 364-day credit facility due November 15, 2019(a)	$—	$—
$4 billion credit facility due November 16, 2023(a)	—	—
$5 billion, five-year credit facility due November 26, 2019, -% and 2.99%, respectively(a)(b)	—	125
Commercial paper notes, 3.10% and 2.02%, respectively(b)	433	240
KML 2018 Credit Facility(c)	—	—
Current portion of senior notes		
6.00%, due January 2018	—	750
7.00%, due February 2018	—	82
5.95%, due February 2018	—	975
7.25%, due June 2018	—	477
9.00%, due February 2019	500	—
2.65%, due February 2019	800	—
3.05%, due December 2019	1,500	—
Trust I Preferred Securities, 4.75%, due March 2028	111	111
Current portion - Other debt	44	68
Total current portion of debt	$3,388	$2,828

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(a) On November 16, 2018, we replaced our $5 billion, five-year credit facility with two new credit facilities discussed further in "—Credit Facilities and Restrictive Covenants" following.

(b) Interest rates are weighted average rates at December 31, 2018 and 2017, respectively.

(c) Borrowings under the KML 2018 Credit Facility are denominated in C$ and are converted to U.S. dollars. The exchange rate was 0.7330 U.S. dollars per C$ at December 31, 2018 and 0.7971 U.S. dollars per C$ at December 31, 2017. See "—Credit Facilities" below.

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.

Subsequent Event—Debt Repayments

Using part of our portion of proceeds from the TMPL Sale that KML distributed to us in January 2019, we immediately repaid our outstanding balance of commercial paper borrowings, and then in February 2019, repaid $500 million of maturing 9.00% senior notes and $800 million of maturing 2.65% senior notes which were included in "Current portion of debt" on the accompanying consolidated balance sheet as of December 31, 2018.

Credit Facilities and Restrictive Covenants

KMI

On November 16, 2018, we replaced our five-year, $5 billion revolving credit facility with (i) a new five-year, $4 billion revolving credit facility (Five-year Credit Facility); and (ii) a new 364-day, $500 million revolving credit facility (364-day Credit Facility) with a syndicate of lenders, together, “KMI’s New Credit Facilities.”

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 Five-year Credit Facility.

Depending on the type of loan request, our credit facility borrowings under either of our credit facilities 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%for the Five-year Credit Facility and 0.090% to 0.275% for the 364-day Credit Facility based upon our debt credit rating.

KMI's New Credit Facilities contain financial and various other covenants that apply to the Company and its subsidiaries and are common in such agreements, including a maximum ratio of Consolidated Net Indebtedness to Consolidated EBITDA (each as defined in the Five-Year Credit Facility and 364-day Credit Facility, as applicable) of 5.50 to 1.00, for any four-fiscal-quarter period. Other negative covenants include restrictions on the Company's and certain of its 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 the Company or any guarantor. KMI's New Credit Facilities also restrict the Company's ability to make certain restricted payments if an event of default (as defined in the Five-Year Credit Facility and the 364-Day Credit Facility) has occurred and is continuing or would occur and be continuing.

As of December 31, 2018, we had no borrowings outstanding under our Five-year Credit Facility or our 364-day Credit Facility, $433 million outstanding under our commercial paper program and $99 million in letters of credit. Our availability under these facilities as of December 31, 2018 was $3,968 million. As of December 31, 2018, we were in compliance with all required covenants.

KML

Upon the closing of the TMPL Sale on August 31, 2018, KML's prior credit facility was replaced with a new 4-year, C$500 million unsecured revolving credit facility for working capital purposes ("KML 2018 Credit Facility") under a credit agreement with the Royal Bank of Canada (the "KML Credit Agreement") as agent. In addition, the C$133 million (U.S.$102 million) of outstanding borrowings under KML's prior credit facility were paid off prior to its termination with a portion of the proceeds from the TMPL Sale.

Depending on the type of loan requested, interest on borrowings outstanding are calculated based on: (i) a Canadian prime rate of interest; (ii) a U.S. base rate; (iii) LIBOR; or (iv) bankers' acceptance fees, plus (i) in the case of Canadian prime rate or U.S. base rate loans, an applicable margin of up to 1.25%; or (ii) in the case of LIBOR or bankers' acceptance loans, an applicable margin ranging from 1.00% to 2.25%, with such margin in any case determined by KML's debt credit rating. Standby fees for the unused portion of the KML 2018 Credit Facility will be calculated at a rate ranging from 0.20% to 0.45% based upon KML's debt credit rating.

The KML Credit Agreement contains various financial and other covenants that apply to KML and its subsidiaries and that are common in such agreements, including a maximum ratio of KML's consolidated total funded debt to its consolidated earnings before interest, income taxes, DD&A, and non-cash adjustments as defined in the KML Credit Agreement, of 5.00:1.00 and restrictions on KML's ability to incur debt, grant liens, make dispositions, engage in transactions with affiliates, make restricted payments, make investments, enter into sale leaseback transactions, amend organizational documents and engage in corporate reorganization transactions.

In addition, the KML Credit Agreement contains customary events of default, including non-payment; non-compliance with covenants (in some cases, subject to grace periods); payment default under, or acceleration events affecting, certain other indebtedness; bankruptcy or insolvency events involving KML or guarantors; and changes of control. If an event of default under the KML Credit Agreement exists and is continuing, the lenders could terminate their commitments and accelerate the maturity of the outstanding obligations under the KML Credit Agreement.

On May 30, 2018, in conjunction with the announcement of the TMPL Sale approximately C$100 million of borrowings outstanding under KML's June 16, 2017 revolving credit facilities (the "KML 2017 Credit Facility") were repaid, the underlying credit facilities were terminated, and approximately $46 million of deferred costs associated with the KML 2017 Credit Facility that were being amortized as interest expense over its term were written off.

As of December 31, 2018, KML had no borrowings outstanding under the KML 2018 Credit Facility, and had C$489 million (U.S. $359 million) available under the KML 2018 Credit Facility, after reducing the C$500 million (U.S.$367 million) capacity for the C$11 million (U.S.$8 million) in letters of credit. Of the total C$11 million of letters of credit issued, approximately C$8 million are related to Trans Mountain for which it has issued a backstop letter of credit to KML. As of December 31, 2018, KML was in compliance with all required covenants. As of December 31, 2017, KML had no borrowings outstanding under the KML 2017 Credit Facility.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2018, are summarized as follows (in millions):

Year	Total
2019	$3,388
2020	2,205
2021	2,422
2022	2,518
2023	3,250
Thereafter	22,810
Total	$36,593

Debt Fair Value Adjustments

The carrying value adjustment to debt securities whose fair value is being hedged is included within “Debt fair value adjustments” on our accompanying consolidated balance sheets. “Debt fair value adjustments” also include unamortized debt discount/premiums, purchase accounting debt fair value adjustments, unamortized portion of proceeds received from the early termination of interest rate swap agreements, and debt issuance costs. As of December 31, 2018, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 16 years. The following table summarizes the “Debt fair value adjustments” included on our accompanying consolidated balance sheets (in millions):

	December 31,	
Debt Fair Value Adjustments	2018	2017
Purchase accounting debt fair value adjustments	$658	$719
Carrying value adjustment to hedged debt	2	115
Unamortized portion of proceeds received from the early termination of interest rate swap agreements	275	297
Unamortized debt discounts, net	(74)	(74)
Unamortized debt issuance costs	(130)	(130)
Total debt fair value adjustments	$731	$927

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 5.15% during 2018 and 5.02% during 2017. 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, 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 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 2018, 2017 and 2016, we made restricted Class P common stock grants to our non-employee directors of 25,800, 17,740 and 31,880, respectively. These grants were valued at time of issuance at $500,000, $400,000 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, 2018		Year Ended December 31, 2017		Year Ended December 31, 2016	
	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	10,518,344	$ 28.21	9,038,137	$ 32.72	7,645,105	$ 37.91
Granted	5,389,476	17.73	3,221,691	19.52	2,816,599	21.36
Vested	(2,371,193)	36.34	(1,501,939)	36.67	(1,226,652)	38.53
Forfeited	(382,022)	23.26	(239,545)	28.34	(196,915)	35.74
Outstanding at end of period	13,154,605	22.59	10,518,344	28.21	9,038,137	32.72

The intrinsic value of restricted stock awards vested during the years ended December 31, 2018, 2017 and 2016 was $42 million, $30 million and $25 million, respectively. Restricted stock awards made to employees have vesting periods ranging from 1 year with variable vesting dates to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares

2019	4,048,963
2020	3,537,544
2021	4,814,403
2022	152,104
2023	121,093
Thereafter	480,498
Total Outstanding	13,154,605

The related compensation costs less estimated forfeitures is generally recognized ratably over the vesting period of the restricted stock awards. Upon vesting, the grants will be paid in our Class P common shares.

During 2018, 2017 and 2016, we recorded $63 million, $65 million and $66 million, respectively, in expense related to restricted stock awards and capitalized approximately $13 million, $9 million and $9 million, respectively. At December 31, 2018 and 2017, unrecognized restricted stock awards compensation costs, less estimated forfeitures, was approximately $127 million with a weighted average remaining amortization period of 2.32 years.

KML Restricted Shares

KML adopted the 2017 Restricted Share Unit Plan for Employees, an equity awards plan, for its eligible employees, and the 2017 Restricted Share Unit Plan for Non-Employee Directors, in which its eligible non-employee directors participate. During the year ended December 31, 2018 and 2017, we recognized $6 million and $1 million, respectively, of expense and capitalized $2 million and $1 million, respectively, related to these compensation programs. At December 31, 2018, unrecognized compensation costs, less estimated forfeitures associated with KML's restricted share unit awards, was approximately $3 million, with a weighted average remaining amortization period of 2.1 years.

Pension and Other Postretirement Benefit 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. The total cost for our savings plan was approximately $48 million, $47 million, and $47 million for the years ended December 31, 2018, 2017 and 2016, 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 distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees accrue benefits through career pay or final pay formulas.

Other Postretirement Benefit Plans

We and certain of our subsidiaries provide other postretirement benefits (OPEB), 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). Prior to 2018, we included the net periodic benefit costs, contributions and liability amounts associated with our Canadian pension plans within our consolidated financial statements. In conjunction with the sale, Kinder Morgan Canada Services was formed and became the Canadian employer of the staff that operates 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.

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, 2018 and 2017 (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Change in benefit obligation:				
Benefit obligation at beginning of period	$2,982	$2,884	$425	$473
Service cost	52	40	1	1
Interest cost	84	88	12	13
Actuarial (gain) loss	(172)	155	(53)	(16)
Benefits paid	(175)	(180)	(33)	(38)
Participant contributions	—	3	1	2
Medicare Part D subsidy receipts	—	—	1	1
Exchange rate changes	—	13	—	1
Settlements	—	(21)	—	—
Other(a)	(205)	—	(15)	(12)
Benefit obligation at end of period	2,566	2,982	339	425
Change in plan assets:				
Fair value of plan assets at beginning of period	2,296	2,160	335	332
Actual return on plan assets	(128)	292	(5)	29
Employer contributions	30	32	7	9
Participant contributions	—	3	1	2
Medicare Part D subsidy receipts	—	—	1	1
Benefits paid	(175)	(180)	(33)	(38)
Exchange rate changes	—	10	—	—
Settlements	—	(21)	—	—
Other(a)	(159)	—	—	—
Fair value of plan assets at end of period	1,864	2,296	306	335
Funded status - net liability at December 31,	$(702)	$(686)	$(33)	$(90)

(a) 2018 amounts represent December 31, 2017 balances associated with Canadian pension and OPEB plans that were included in the TMPL Sale. 2017 amounts represent December 31, 2016 balances associated with our Plantation Pipeline OPEB plan that are no longer included in these disclosures.

Components of Funded Status. The following table details the amounts recognized in our balance sheets at December 31, 2018 and 2017 related to our pension and OPEB plans (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Non-current benefit asset(a)	$—	$—	$190	$198
Current benefit liability	—	—	(13)	(15)
Non-current benefit liability	(702)	(686)	(210)	(273)
Funded status - net liability at December 31,	$(702)	$(686)	$(33)	$(90)

(a) 2018 and 2017 OPEB amounts include $32 million and $33 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, 2018 and 2017 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets, including the portion attributable to our noncontrolling interests, (in millions):

	Pension Benefits		OPEB	
	2018	2017	2018	2017
Unrecognized net actuarial (loss) gain	$(653)	$(635)	$117	$88
Unrecognized prior service (cost) credit	(3)	(4)	14	17
Accumulated other comprehensive (loss) income	$(656)	$(639)	$131	$105

We anticipate that approximately $40 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 2019, including approximately $42 million of unrecognized net actuarial loss and approximately $2 million of unrecognized prior service credit.

Our accumulated benefit obligation for our pension plans was $2,535 million and $2,840 million at December 31, 2018 and 2017, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $293 million and $373 million at December 31, 2018 and 2017, respectively. The fair value of these plans' assets was approximately $70 million and $84 million at December 31, 2018 and 2017, respectively.

Plan Assets. The investment policies and strategies are established by the 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 (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) 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, 2018, 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, 2018, the allowable range for asset allocations in effect for our OPEB plans were 42% to 67% equity, 25% to 51% fixed income and 0% to 20% 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, exchange traded mutual funds and MLPs. 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 and immediate participation guarantee contracts. These contracts 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, limited partnerships, and fixed income trusts. 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, 2018 and 2017 (in millions):

	Pension Assets							
	2018				2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Cash	$—	$—	$ —	$—	$6	$—	$ —	$6
Short-term investment funds	—	7	—	7	—	65	—	65
Mutual funds(a)	81	—	—	81	245	—	—	245
Equities(b)	227	—	—	227	278	—	—	278
Fixed income securities	—	422	—	422	—	416	—	416
Derivatives	—	6	—	6	—	5	—	5
Subtotal	$308	$435	$ —	$743	$529	$486	$ —	$1,015
Measured at NAV(c)								
Common/collective trusts(d)				857				895
Private investment funds(e)				215				337
Private limited partnerships(f)				49				49
Subtotal				1,121				1,281
Total plan assets fair value				$1,864				$2,296

(a) Includes mutual funds which are invested in equity.
(b) Plan assets include $94 million and $110 million of KMI Class P common stock for 2018 and 2017, respectively.
(c) Plan assets for which fair value was measured using NAV as a practical expedient.
(d) Common/collective trust funds were invested in approximately 37% fixed income and 63% equity in 2018 and 36% fixed income and 64% equity in 2017.
(e) Private investment funds were invested in approximately 71% fixed income and 29% equity in 2018 and 52% fixed income and 48% equity in 2017.
(f) Includes assets invested in real estate, venture and buyout funds.

	OPEB Assets							
	2018				2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Measured within fair value hierarchy								
Short-term investment funds	$—	$ 4	$ —	$4	$—	$ 7	$ —	$7
Equities(a)	—	—	—	—	16	—	—	16
MLPs	—	—	—	—	50	—	—	50
Guaranteed insurance contracts	—	—	51	51	—	—	49	49
Mutual funds	1	—	—	1	1	—	—	1
Subtotal	$1	$ 4	$ 51	$56	$67	$ 7	$ 49	$123
Measured at NAV(b)								
Common/collective trusts(c)				250				68
Fixed income trusts				—				66
Limited partnerships(d)				—				78
Subtotal				250				212
Total plan assets fair value				$306				$335

(a) Plan assets include $2 million of KMI Class P common stock for 2017.
(b) Plan assets for which fair value was measured using NAV as a practical expedient.
(c) Common/collective trust funds were invested in approximately 60% equity and 40% fixed income securities for 2018 and 71% equity and 29% fixed income securities for 2017.
(d) Limited partnerships were invested in global equity securities.

The following tables present the changes in our pension and OPEB plans' assets included in Level 3 for the years ended December 31, 2018 and 2017 (in millions):

	Pension Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2017					
Insurance contracts	$16	$ —	$ —	$ (16)	$ —

	OPEB Assets				
	Balance at Beginning of Period	Transfers In (Out)	Realized and Unrealized Gains (Losses), net	Purchases (Sales), net	Balance at End of Period
2018					
Insurance contracts	$49	$ —	$ 4	$ (2)	$ 51
2017					
Insurance contracts	$47	$ —	$ 5	$ (3)	$ 49

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, 2018 and 2017.

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Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2018, we expect to make the following benefit payments under our plans (in millions):

Fiscal year	Pension Benefits	OPEB(a)
2019	$ 234	$ 33
2020	233	32
2021	225	32
2022	223	31
2023	214	29
2024 - 2028	969	127

(a) Includes a reduction of approximately $2 million in each of the years 2019 - 2023 and approximately $13 million in aggregate for 2024 - 2028 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In 2019, we expect to contribute approximately $60 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 2018, 2017 and 2016:

	Pension Benefits			OPEB		
	2018	2017	2016	2018	2017	2016
Assumptions related to benefit obligations:						
Discount rate	4.26%	3.56%	3.83%	4.16%	3.48%	3.69%
Rate of compensation increase	3.50%	3.53%	3.52%	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate for benefit obligations	3.56%	3.83%	4.05%	3.48%	3.69%	3.91%
Discount rate for interest on benefit obligations	3.13%	3.09%	3.24%	3.08%	3.05%	3.18%
Discount rate for service cost	3.56%	3.88%	4.15%	3.82%	4.15%	4.36%
Discount rate for interest on service cost	3.14%	3.24%	3.50%	3.76%	3.95%	4.17%
Expected return on plan assets(a)	7.25%	7.07%	7.31%	7.08%	6.84%	7.07%
Rate of compensation increase	3.50%	3.52%	3.51%	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 21% for 2018, 2017 and 2016.

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 assumed a weighted-average annual rate of increase in the per capita cost of covered health care benefits of 7.26%, gradually decreasing to 4.54% by the year 2038. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2018 and 2017 (in millions):

	2018	2017
One-percentage point increase:		
Aggregate of service cost and interest cost	$1	$1
Accumulated postretirement benefit obligation	16	22
One-percentage point decrease:		
Aggregate of service cost and interest cost	$(1)	$(1)
Accumulated postretirement benefit obligation	(14)	(19)

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		
	2018	2017	2016	2018	2017	2016
Components of net benefit cost:						
Service cost	$52	$40	$36	$1	$1	$1
Interest cost	84	88	89	12	13	16
Expected return on assets	(149)	(147)	(151)	(20)	(19)	(19)
Amortization of prior service cost (credit)	—	1	1	(4)	(3)	(3)
Amortization of net actuarial loss (gain)	40	52	35	(6)	(6)	—
Curtailment and settlement loss	—	5	—	—	—	—
Net benefit (credit) cost(a)	27	39	10	(17)	(14)	(5)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net loss (gain) arising during period	105	17	116	(32)	(25)	(48)
Prior service cost (credit) arising during period	—	—	—	—	—	—
Amortization or settlement recognition of net actuarial (loss) gain	(87)	(64)	(34)	3	6	—
Amortization of prior service (cost) credit	(1)	(1)	—	3	1	1
Exchange rate changes	—	—	1	—	—	—
Total recognized in total other comprehensive (income) loss	17	(48)	83	(26)	(18)	(47)
Total recognized in net benefit cost (credit) and other comprehensive (income) loss	$44	$(9)	$93	$(43)	$(32)	$(52)

(a) 2018 and 2017 OPEB amounts each include $4 million of net benefit credits related to a plan that we sponsor that is associated with employee services provided to an unconsolidated joint venture. We charge or refund these costs or credits associated with this plan to the joint venture as an offset to our net benefit cost or credit and receive our proportionate share of these costs or credits through our share of the equity investee's earnings.

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, 2018, 2017 and 2016. We consider the overall multi-employer pension plan liability exposure to be minimal in relation to the value of its total consolidated assets and net income.

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 current 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. The following table provides information regarding our preferred stock dividends:

Period	Total dividend per share for the period	Date of declaration	Date of record	Date of dividend
January 26, 2018 through April 25, 2018	$24.375	January 17, 2018	April 11, 2018	April 26, 2018
April 26, 2018 through July 25, 2018	24.375	April 18, 2018	July 11, 2018	July 26, 2018
July 26, 2018 through October 25, 2018	24.375	July 18, 2018	October 11, 2018	October 26, 2018

Common Equity

As of December 31, 2018, 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, 2018 and 2017, we repurchased approximately 15 million and 14 million, respectively, of our Class P shares for approximately $273 million and $250 million, respectively. 2018 amounts exclude repurchases made in December 2018 of approximately 0.1 million of our Class P shares for approximately $2 million which settled on January 2, 2019.

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, 2018, 2017 and 2016 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,		
	2018	2017	2016
Per common share cash dividend declared for the period	$0.80	$0.50	$0.50
Per common share cash dividend paid in the period	0.725	0.50	0.50

On January 16, 2019, our board of directors declared a cash dividend of $0.20 per common share for the quarterly period ended December 31, 2018, which is payable on February 15, 2019 to shareholders of record as of January 31, 2019.

Warrants

The warrant repurchase program dated June 12, 2015, which authorized us to repurchase up to $100 million of warrants, expired along with the warrants on May 25, 2017, at which time 293 million of unexercised warrants to buy KMI common stock expired without the issuance of Class P common stock. Prior to expiration, each of the warrants entitled the holder to purchase one share of our common stock for an exercise price of $40 per share, payable in cash or by cashless exercise.

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,	
	2018	2017
KML(a)	$514	$1,163
Others	339	325
	$853	$1,488

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(a) The reduction in the noncontrolling interests associated with KML is primarily attributable to the accrual of the return of capital distribution for the net proceeds from the TMPL Sale paid to KML’s Restricted Voting Shareholders on January 3, 2019 of approximately $0.9 billion.

KML Contributions

KML Restricted Voting Shares

As discussed in Note 3, on May 30, 2017 our 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 represents an approximate 30% interest in our Canadian operations and is reflected within “Noncontrolling interests” in our consolidated financial statements as of and for the period presented after May 30, 2017.

KML 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 recently 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

KML has a dividend policy pursuant to which it may pay a quarterly dividend on its restricted voting shares in an amount based on a portion of its DCF. The payment of dividends is not guaranteed and the amount and timing of any dividends payable will be at the discretion of KML's board of directors. If declared by KML's board of directors, KML will pay quarterly dividends, on or about the 45th day (or next business day) following the end of each calendar quarter to holders of its restricted voting shares of record as of the close of business on or about the last business day of the month following the end of each calendar quarter. KML also established a Dividend Reinvestment Plan (DRIP) which allows holders (excluding holders not resident in Canada) of restricted voting shares to elect to have any or all cash dividends payable to such shareholder automatically reinvested in additional restricted voting shares at a price per share calculated by reference to the volume-weighted average of the closing price of the restricted voting shares on the stock exchange on which the restricted voting shares are then listed for the five trading days immediately preceding the relevant dividend payment date, less a discount of between 0% and 5% (as determined from time to time by KML's board of directors, in its sole discretion).

Subsequent Event

On January 16, 2019, KML's board of directors announced that it would suspend KML's DRIP, effective with the payment of the fourth quarter 2018 dividend noted above, in light of KML's reduced need for capital.

KML also pays dividends on its Series 1 Preferred Shares and Series 3 Preferred Shares, which are fixed, cumulative, preferential, and payable quarterly in the annual amount of C$1.3125 per share and C$1.3000 per share, respectively, on the 15th day of February, May, August and November, as and when declared by KML's board of directors, for the initial fixed rate period to but excluding November 15, 2022 and February 15, 2023, respectively.

During the years ended December 31, 2018 and 2017, KML paid dividends on its Restricted Voting Shares to the public valued at $52 million and $18 million, respectively, of which $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 Series 1 and Series 3 Preferred Shares of $21 million for the year ended December 31, 2018 and on its Series 1 Preferred Shares of $3 million for the year ended December 31, 2017.

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 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 (in millions):

	December 31,	
	2018	2017
Balance sheet location		
Accounts receivable, net	$48	$34
Other current assets	2	8
Deferred charges and other assets	55	23
	$105	$65
Current portion of debt	$6	$6
Accounts payable	26	18
Other current liabilities	7	4
Long-term debt	148	155
Other long-term liabilities and deferred credits	34	35
	$221	$218

	Year Ended December 31,		
	2018	2017	2016
Income statement location			
Revenues			
Services	$171	$73	$71
Product sales and other	94	89	71
	$265	$162	$142
Operating Costs, Expenses and Other			
Costs of sales	$63	$20	$38
Other operating expenses	91	100	75

13. Commitments and Contingent Liabilities

Leases and Rights-of-Way Obligations

The table below depicts future gross minimum rental commitments under our operating leases and rights-of-way obligations as of December 31, 2018 (in millions):

Year	Commitment
2019	$ 122
2020	107
2021	102
2022	97
2023	81
Thereafter	353
Total minimum payments	$ 862

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to thirty-five years. Total lease and rental expenses were $155 million, $140 million and $138 million for the years ended December 31, 2018, 2017 and 2016, respectively. The amount of capital leases included within “Property, plant and equipment, net” in our accompanying consolidated balance sheets as of December 31, 2018 and 2017 is not material to our consolidated balance sheets.

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, 2018 and 2017, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $714 million and $1,070 million, respectively. December 31, 2018 and 2017 amounts are represented by our proportional share of the debt obligations of four and three 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. Also included in our contingent debt obligations is a guarantee of a throughput and deficiency agreement supporting certain debt obligations of a subsidiary of our investee, Cortez Pipeline Company. Through this guarantee, we are severally liable for approximately 50% of a Cortez Pipeline Company subsidiary's debt obligations with respect to a $50 million credit facility and $100 million in bonds. In addition, we have guaranteed approximately 100% of the debt issued by another Cortez Pipeline Company subsidiary to fund an expansion project, of which debt consists of a $27 million credit facility and a $120 million private placement note.

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 and net investments in foreign operations. 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."

Energy Commodity Price Risk Management

As of December 31, 2018, 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	(21.6)	MMBbl
Crude oil basis	(13.7)	MMBbl
Natural gas fixed price	(33.3)	Bcf
Natural gas basis	(26.1)	Bcf
Derivatives not designated as hedging contracts		
Crude oil fixed price	(0.5)	MMBbl
Crude oil basis	(4.5)	MMBbl
Natural gas fixed price	(4.5)	Bcf
Natural gas basis	(26.9)	Bcf
NGL fixed price	(3.2)	MMBbl

As of December 31, 2018, 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 2022.

Interest Rate Risk Management

As of December 31, 2018 and 2017, we had a combined notional principal amount of $10,575 million and $9,575 million, respectively, of fixed-to-variable interest rate swap agreements, all of which were designated as fair value hedges. All of our swap agreements effectively convert the interest expense associated with certain series of senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread and have termination dates that correspond to the maturity dates of the related series of senior notes. As of December 31, 2018, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of debt due to interest rate risk is through March 15, 2035.

Foreign Currency Risk Management

As of both December 31, 2018 and 2017, we had a notional principal amount of $1,358 million of cross-currency swap agreements to manage the foreign currency risk related to our Euro denominated senior notes by effectively converting all of the 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 equivalent to approximately 3.79% and 4.67% for the 7-year and 12-year senior notes, respectively. These cross-currency swaps are accounted for as cash flow hedges. The terms of the cross-currency swap agreements correspond to the related hedged senior notes, and such agreements have the same maturities as the hedged senior notes.

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.$1,888 million). These swaps result in our selling fixed C$ 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 while

outstanding were reflected in the CTA section of OCI.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets (in millions):
Fair Value of Derivative Contracts

	Location	Asset derivatives		Liability derivatives	
		December 31,		December 31,	
		2018	2017	2018	2017
		Fair value		Fair value	
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	$ 135	$ 65	$ (45)	$ (53)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	64	14	—	(24)
Subtotal		199	79	(45)	(77)
Interest rate contracts	Fair value of derivative contracts/(Other current liabilities)	12	41	(37)	(3)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	121	164	(78)	(62)
Subtotal		133	205	(115)	(65)
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)	106	166	—	—
Subtotal		197	166	(6)	(6)
Total		529	450	(166)	(148)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Fair value of derivative contracts/(Other current liabilities)	22	8	(5)	(22)
	Deferred charges and other assets/(Other long-term liabilities and deferred credits)	—	—	—	(2)
Total		22	8	(5)	(24)
Total derivatives		$ 551	$ 458	$ (171)	$ (172)

Effect of Derivative Contracts on the Income Statement

The following tables summarize the pre-tax impact of our derivative contracts in our accompanying consolidated statements of 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,		
		2018	2017	2016
Interest rate contracts	Interest, net	$ (122)	$ (103)	$ (180)
Hedged fixed rate debt	Interest, net	$ 113	$ 105	$ 160

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Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative (effective portion)(a)			Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)			Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)		
	Year Ended December 31,				Year Ended December 31,				Year Ended December 31,		
	2018	2017	2016		2018	2017	2016		2018	2017	2016
Energy commodity derivative contracts	$201	$37	$(182)	Revenues—Natural gas sales	$(29)	$18	$23	Revenues—Natural gas sales	$—	$—	$—
				Revenues—Product sales and other	(30)	55	233	Revenues—Product sales and other	(65)	11	(12)
				Costs of sales	21	14	(26)	Costs of sales	—	—	—
Interest rate contracts(c)	3	—	(3)	Interest, net	(4)	(5)	(4)	Interest, net	—	—	—
Foreign currency contracts	(59)	190	21	Other, net	(67)	186	(43)	Other, net	—	—	—
Total	$145	$227	$(164)	Total	$(109)	$268	$183	Total	$(65)	$11	$(12)

(a) We expect to reclassify an approximate $165 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2018 into earnings during the next twelve months (when the associated forecasted transactions are also expected to occur); however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) 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 (effective portion)	Location	Gain/(loss) reclassified from Accumulated OCI into income (effective portion)(a)	Location	Gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)
	Year Ended December 31,		Year Ended December 31,		Year Ended

	2018	2017	2016		2018	2017	2016		December 31, 2018	2017	2016
Foreign currency contracts	$ 91	$ —	$ —	Loss on impairments and divestitures, net	$ 26	$ —	$ —	Other, net	$ —	$ —	$ —
Total	$ 91	$ —	$ —	Total	$ 26	$ —	$ —	Total	$ —	$ —	$ —

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(a) During the year ended December 31, 2018, we recognized a $26 million gain from our accumulated other comprehensive loss balance related to the TMPL Sale. See Note 3.

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Derivatives not designated as accounting hedges	Location	Gain/(loss) recognized in income on derivatives Year Ended December 31,		
		2018	2017	2016
Energy commodity derivative contracts	Revenues—Natural gas sales	$3	$20	$(10)
	Revenues—Product sales and other	(12)	(16)	(26)
	Costs of sales	2	—	3
Interest rate contracts	Interest, net	—	—	63
Total(a)		$(7)	$4	$30

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(a) For the years ended December 31, 2018, 2017 and 2016 includes approximate losses of $4 million and gains of $57 million and $73 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2018 and 2017, we had no outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2018, we had cash margins of $16 million posted by our counterparties with us as collateral and reported within "Other Current Liabilities" on our accompanying consolidated balance sheet. As of December 31, 2017, we had cash margins of $1 million posted by us with our counterparties as collateral and reported within "Restricted deposits" on our accompanying consolidated balance sheet. The balance at December 31, 2018 consisted of initial margin requirements of $9 million offset by variation margin requirements of $25 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, 2018, based on our current mark to market positions and posted collateral, we estimate that if our credit rating were downgraded one or two notches we would not be required to post additional collateral.

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, 2015	$ 219	$ (322)	$ (358)	$ (461)
Other comprehensive (loss) gain before reclassifications	(104)	34	(14)	(84)
Gains reclassified from accumulated other comprehensive loss	(116)	—	—	(116)
Net current-period other comprehensive (loss) income	(220)	34	(14)	(200)
Balance at December 31, 2016	(1)	(288)	(372)	(661)
Other comprehensive gain before reclassifications	145	55	40	240
Gains reclassified from accumulated other comprehensive loss	(171)	—	—	(171)
KML IPO	—	44	7	51
Net current-period 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 (Note 1)	(4)	(36)	(69)	(109)
Net current-period other comprehensive income (loss)	191	98	(78)	211
Balance at December 31, 2018	$ 164	$ (91)	$ (403)	$ (330)

(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.

15. 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. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's

own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; (ii) interest rate swap agreements; and (iii) cross-currency swap agreements, 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, 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
As of December 31, 2017							
Energy commodity derivative contracts(a)	$17	$70	$—	$87	$(42)	$(12)	$33
Interest rate contracts	$—	$205	$—	$205	$(15)	$—	$190
Foreign currency contracts	$—	$166	$—	$166	$(6)	$—	$160

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Collateral posted(b)	Net amount
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	$—	$—
As of December 31, 2017							
Energy commodity derivative contracts(a)	$(3)	$(98)	$—	$(101)	$42	$—	$(59)
Interest rate contracts	$—	$(65)	$—	$(65)	$15	$—	$(50)
Foreign currency contracts	$—	$(6)	$—	$(6)	$6	$—	$—

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

Fair Value of Financial Instruments

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

	December 31, 2018		December 31, 2017	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total debt	$37,324	$ 37,469	$37,843	$ 40,050

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2018 and 2017.

16. Revenue Recognition

Adoption of Topic 606

Effective January 1, 2018, we adopted ASU No. 2014-09, “Revenue from Contracts with Customers” and the series of related accounting standard updates that followed (collectively referred to as “Topic 606”). We utilized the modified retrospective method to adopt Topic 606, which required us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) revenue contracts that were not completed as of January 1, 2018. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 were not revised. The cumulative effect of this adoption of Topic 606 as of January 1, 2018 was not material.

The impact to our consolidated financial statement line items from the adoption of Topic 606 for these changes was as follows (in millions):

	Year ended December 31, 2018		
Line Item	As Reported	Amounts Without Adoption of Topic 606	Effect of Change Increase/(Decrease)
Consolidated Statement of Income			
Natural gas sales	$3,281	$ 3,339	$ (58)
Services	7,931	8,134	(203)
Product sales and other	2,932	3,270	(338)
Total Revenues	14,144	14,743	(599)
Cost of sales	4,421	5,020	(599)
Operating Income	3,794	3,794	—

The effect-of-change amounts in the table above are attributable to the non-FERC-regulated portion of our Natural Gas Pipelines business segment, which provides gathering, processing and processed commodity sales services for various producers.

In those instances where we purchase and obtain control of the entire natural gas stream in our producer arrangements, we have determined these are contracts with suppliers rather than contracts with customers, and therefore, these arrangements are not included in the scope of Topic 606. These supplier arrangements are subject to updated guidance in ASC 705, Cost of Sales and Services, whereby any embedded fees within such contracts, which historically have been reported as Services revenue, are now reported as a reduction to Cost of sales upon adoption of Topic 606.

In our natural gas processing arrangements where we extract and sell the commodities derived from the processed natural gas stream (i.e., residue gas or NGLs), we may take control of: (i) none of the commodities we sell, (ii) a portion of the commodities we sell, or (iii) all of the commodities we sell.

In those instances where we remit all of the cash proceeds received from third parties for selling the extracted commodities, less the fees attributable to these arrangements, we have determined that the producer has control over these commodities. Upon adoption of Topic 606, we eliminated recording both sales revenue (Natural gas and Product) and Cost of sales amounts and now only record fees attributable to these arrangements to Service revenues.

In other instances where we do not obtain control of the extracted commodities we sell, we are acting as an agent for the producer and, upon adoption of Topic 606, we have continued to recognize Services revenue for the net amount of consideration we retain in exchange for our service.

When we purchase and obtain control of a portion of the residue gas or NGLs we sell, we have determined these arrangements contain both a supply and a service revenue element and therefore are partially in the scope of Topic 606. In these arrangements, the producer is a supplier for the cash settled portion of the commodity we purchase and a customer with regards to the service provided to gather and redeliver the other component. Upon adoption of Topic 606, fees attributable to the supply element are recorded as a reduction to Cost of sales and fees attributable to the service element are recorded as Services revenue. Previously, we recognized Services revenue for both elements.

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 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 based on a 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.

CO_2 Segment

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

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, 2018						
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Kinder Morgan Canada	Corporate and Eliminations	Total
Revenues from contracts with customers(a)							
Services							
Firm services(b)	$3,215	$ 566	$ 976	$2	$ —	$ (13)	$4,746
Fee-based services	860	791	581	67	167	—	2,466
Total services revenues	4,075	1,357	1,557	69	167	(13)	7,212
Sales							
Natural gas sales	3,319	—	—	2	—	(11)	3,310
Product sales	1,333	216	18	1,222	—	(1)	2,788
Other sales	8	—	—	—	—	—	8
Total sales revenues	4,660	216	18	1,224	—	(12)	6,106
Total revenues from contracts with customers	8,735	1,573	1,575	1,293	167	(25)	13,318
Other revenues(c)	280	140	444	(38)	3	(3)	826
Total revenues	$9,015	$ 1,713	$ 2,019	$1,255	$ 170	$ (28)	$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 and derivatives. The majority of our lease revenues are from certain firm service contracts that are accounted for as operating leases. See Note 14 for additional information related to our derivative contracts.

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.

The following table presents the activity in our contract assets and liabilities (in millions):

	Year ended December 31, 2018
Contract Assets	
Balance at January 1, 2018	$ 32
Additions	59
Transfer to Accounts receivable	(67)
Balance at December 31, 2018(a)	$ 24
Contract Liabilities	
Balance at January 1, 2018	$ 206
Additions	453
Transfer to Revenues	(360)
Other(b)	(7)
Balance at December 31, 2018(c)	$ 292

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(a) Includes current and non-current balances of $14 million and $10 million reported within “Other current assets” and “Deferred charges and other assets,” respectively, in our accompanying consolidated balance sheet at December 31, 2018.

(b) Includes 2018 foreign currency translation adjustments associated with the balances at December 31, 2017.

(c) Includes current and non-current balances of $80 million and $212 million reported within “Other current liabilities” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheet at December 31, 2018.

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, 2018 that we will invoice or transfer from contract liabilities and recognize in future periods (in millions):

Year	Estimated Revenue
2019	$ 4,881
2020	4,182
2021	3,528
2022	3,011
2023	2,497
Thereafter	14,138
Total	$ 32,237

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 or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services; (ii) contracts with an original expected duration of one year or less; and (iii) contracts for which we recognize revenue at the amount for which we have the right to invoice for services performed.

17. 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 and crude oil gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, NGL and 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 that transload and store refined petroleum products, crude oil, ethanol and chemicals, and bulk products, including petroleum coke, metals and ores; and (ii) Jones Act tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gas 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, 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 either market value or, in some instances, book value.

During 2018, 2017 and 2016, 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,		
	2018	2017	2016
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$9,004	$8,608	$7,998
Intersegment revenues	11	10	7
Products Pipelines			
Revenues from external customers	1699	1645	1631
Intersegment revenues	14	16	18
Terminals			
Revenues from external customers	2,017	1,965	1,921
Intersegment revenues	2	1	1
CO2	1,255	1,196	1,221
Kinder Morgan Canada	170	256	253
Corporate and intersegment eliminations(a)	(28)	8	8
Total consolidated revenues	$14,144	$13,705	$13,058

	Year Ended December 31,		
	2018	2017	2016
Operating expenses(b)			
Natural Gas Pipelines	$5,353	$5,457	$4,393
Products Pipelines	594	487	573
Terminals	818	788	768
CO_2	453	394	399
Kinder Morgan Canada	72	95	87
Corporate and intersegment eliminations	(2)	(6)	2
Total consolidated operating expenses	$7,288	$7,215	$6,222

	Year Ended December 31,		
	2018	2017	2016
Other expense (income)(c)			
Natural Gas Pipelines	$ 593	$ 26	$ 199
Products Pipelines	34	—	76
Terminals	54	(14)	99
CO_2	79	(1)	19
Kinder Morgan Canada	(596)	—	—
Corporate	—	1	(7)
Total consolidated other expense (income)	$ 164	$ 12	$ 386

	Year Ended December 31,		
	2018	2017	2016
DD&A			
Natural Gas Pipelines	$ 1,058	$ 1,011	$ 1,041
Products Pipelines	228	216	221
Terminals	484	472	435
CO_2	473	493	446
Kinder Morgan Canada	29	46	44
Corporate	25	23	22
Total consolidated DD&A	$ 2,297	$ 2,261	$ 2,209

	Year Ended December 31,		
	2018	2017	2016
Earnings from equity investments and amortization of excess cost of equity investments, including loss on impairments			
Natural Gas Pipelines	$ 391	$ 253	$ (269)
Products Pipelines	75	48	56
Terminals	22	24	19
CO_2	34	42	22
Total consolidated equity earnings	$ 522	$ 367	$ (172)

	Year Ended December 31,		
	2018	2017	2016
Other, net-income (expense)			
Natural Gas Pipelines	$ 37	$ 49	$ 19
Products Pipelines	3	(1)	2
Terminals	2	8	4
Kinder Morgan Canada	26	25	15
Corporate	39	16	38
Total consolidated other, net-income (expense)	$ 107	$ 97	$ 78

	Year Ended December 31,		
	2018	2017	2016
Segment EBDA(d)			
Natural Gas Pipelines	$3,580	$3,487	$3,211
Products Pipelines	1,173	1,231	1,067
Terminals	1,171	1,224	1,078
CO_2	759	847	827
Kinder Morgan Canada	720	186	181
Total segment EBDA	7,403	6,975	6,364
DD&A	(2,297)	(2,261)	(2,209)
Amortization of excess cost of equity investments	(95)	(61)	(59)
General and administrative and corporate charges	(588)	(660)	(652)
Interest, net	(1,917)	(1,832)	(1,806)
Income tax expense	(587)	(1,938)	(917)
Total consolidated net income	$1,919	$223	$721

	Year Ended December 31,		
	2018	2017	2016
Capital expenditures			
Natural Gas Pipelines	$ 1,620	$ 1,376	$ 1,227
Products Pipelines	150	127	244
Terminals	380	888	983
CO_2	397	436	276
Kinder Morgan Canada	332	338	124
Corporate	25	23	28
Total consolidated capital expenditures	$ 2,904	$ 3,188	$ 2,882

	2018	2017
Investments at December 31		
Natural Gas Pipelines	$6,358	$6,218
Products Pipelines	839	777
Terminals	268	263
CO_2	16	6
Kinder Morgan Canada	—	34
Total consolidated investments	$7,481	$7,298

	2018	2017
Assets at December 31		
Natural Gas Pipelines	$51,562	$51,173
Products Pipelines	8,429	8,539
Terminals	9,283	9,935
CO_2	3,928	3,946
Kinder Morgan Canada	—	2,080
Corporate assets(e)	5,664	3,382
Total consolidated assets	$78,866	$79,055

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(a) 2017 and 2016 amounts include a management fee of $35 million and $34 million, respectively, for services we perform as operator of an equity investee.
(b) Includes costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
(c) Includes loss on impairments and divestitures, net and other income, net.
(d) Includes revenues, earnings from equity investments, other, net, less operating expenses, loss on impairments and divestitures, net, loss on impairments and divestitures of equity investments, net and other income, net.
(e) 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.

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,		
	2018	2017	2016
Revenues from external customers			
U.S.	$13,596	$13,073	$12,459
Canada	447	503	483
Mexico and other foreign	101	129	116
Total consolidated revenues from external customers	$14,144	$13,705	$13,058

	December 31,		
	2018	2017	2016
Long-term assets, excluding goodwill and other intangibles			
U.S.	$47,468	$47,928	$49,125
Canada	748	3,071	2,399
Mexico and other foreign	83	80	82
Total consolidated long-lived assets	$48,299	$51,079	$51,606

18. Litigation, Environmental and Other Contingencies

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 on our business, financial position, results of operations or dividends to our shareholders. 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

On March 15, 2018, FERC issued a notice of proposed rule-making (NOPR) which proposed a process to implement for ratemaking purposes the 2017 Tax Reform. The NOPR proposed that each regulated interstate natural gas pipeline make a mandatory filing (Form 501-G) to reflect, based upon certain required assumptions, the rate impact of the reduced statutory corporate tax rate, and in the case of master limited partnerships and other pass-through entities, the elimination of an income tax allowance and unspecified resulting treatment of accumulated deferred income tax (ADIT) in the cost of service. The NOPR also provided four options for regulated entities to consider: (1) make a limited filing under section 4 of the NGA to reduce rates for the impact of the 2017 Tax Reform; (2) commit to file a general section 4 rate case in the near future; (3) file an explanation why no rate change is needed, or (4) take no further action other than filing the required Form 501-G report. On July 18, 2018, FERC issued Order No. 849 (Final Rule) promulgating a final rule to implement the 2017 Tax Reform for jurisdictional natural gas pipelines. The Final Rule continues to require the regulated interstate pipelines to file the Form 501-G reflecting certain mandatory assumptions. The Final Rule also maintains substantially the same four options for regulated entities to implement the reduced corporate tax rate. The Final Rule clarifies that pass-through entities whose income consolidates up to a federal income tax paying entity are eligible for a tax allowance. It also clarifies that the required filing is a one-time informational filing and that FERC is not mandating any adjustment in rates as a function of complying with the Final Rule. Companies are also allowed to file an addendum which may reflect an income tax allowance, alternative capital structure and alternative equity returns. The Final Rule establishes a presumption that negotiated rate contracts should not be disturbed. Kinder Morgan filed for rehearing of the Final Rule, but also filed the required Form 501-G filings. We continue to believe any initial, downward rate pressure will be mitigated and spread out over multiple years given the procedural options presented in the Final Rule, the prospective nature of rate changes under section 5 of the NGA and the fact that the FERC affirmed its intention to respect negotiated rate contracts. Many of our transportation and storage services are rendered pursuant to negotiated rate agreements that, consistent with the Final Rule, will not be subject to adjustment due to changes in tax law. Also, many of our current transactions are provided at discounted rates that are below maximum tariff rates, many of which would not be impacted by a change in the maximum tariff rate. Further, on many of our pipelines we are operating under settlements that preclude customers from requesting rate changes at the FERC during the life of the settlement.

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers, the most recent of which was filed in 2015 (docketed at OR16-6) challenging SFPP’s filed East Line rates. 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. If the shippers prevail on their arguments or claims, they are entitled to seek reparations (which may reach back up to two years prior to the filing date of their complaints) or refunds of any excess rates paid, 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. 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. On March 22, 2016, the D.C. Circuit issued a decision in United Airlines, Inc. v. FERC remanding to FERC for further consideration of two issues: (1) the appropriate data to be used to determine the return on equity for SFPP in the underlying docket, and (2) the just and reasonable return to be provided to a tax pass-through entity that includes an income tax allowance in its underlying cost of service. On July 21, 2017, an initial decision by the Administrative Law Judge (ALJ) in OR16-6 concluded that the Complainants are due reparations, with appropriate interest, equal to the difference between what SFPP collected from the Complainants for service on the East Line and the amounts SFPP would have collected had it charged just and reasonable rates for that line. The ALJ ruled that an income tax allowance should be included in the cost of service both to determine reparations and to set going forward rates, and found that the new just and reasonable rates are not knowable until the FERC reviews the initial decision and orders a compliance filing. The FERC will determine which portions of the initial decision to affirm, reject or amend. On March 15, 2018, the FERC announced certain policy changes including a Revised Policy Statement on Treatment of Income Taxes (Revised Policy Statement) and, that same day, the FERC issued orders in a series of pending SFPP proceedings which combined to deny income tax allowance to SFPP, direct SFPP to make compliance filings in its 2008 and 2009 rate filing dockets, and restart the 2011 SFPP complaint proceeding which had been abated. Requests for rehearing were filed in the Revised Policy Statement docket as well as the SFPP dockets in which the Revised Policy Statement was applied. The requests for rehearing in the SFPP dockets remain pending at the FERC. On July 18, 2018, the FERC issued an Order on Rehearing in the Revised Policy Statement docket in which it denied the rehearing petitions and clarified that the issue of entitlement to an income tax allowance will continue to be resolved in individual proceedings, including proceedings involving income tax pass-through entities. The FERC also clarified that when an income tax allowance is eliminated from cost of service, previously ADIT balances associated with such income tax allowance may also be eliminated. SFPP along with another pipeline entity appealed the Revised Policy Statement along with the Order on Rehearing to the D.C. Circuit. With respect to the various SFPP related complaints and protest proceedings at the FERC, we estimate that the shippers are seeking approximately $30 million in annual rate reductions and approximately $330 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, 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 during calendar year 2015. EPNG sought federal appellate review of Opinion 517-A and oral arguments were held on February 15, 2017. On February 21, 2017, the reviewing court delayed the case until the FERC rules on the rehearing requests pending in the 2010 Rate Case. 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 delayed appeal from the 2008 rate case, EPNG's appeal from the 2010 rate case, and the intervenors' delayed appeal in the 2010 case. In accordance with that schedule, EPNG and the intervenors filed their initial briefs on January 8, 2019.

Other Commercial Matters

Union Pacific Railroad Company Easements Landowner Litigation

A purported class action lawsuit was filed in 2015 in a U.S. District Court in California against Union Pacific Railroad Company (UPRR), SFPP, KMGP and Kinder Morgan Operating L.P. "D" by private landowners who claimed to be the lawful owners of subsurface real property allegedly used or occupied by UPRR or SFPP for pipeline easements on rights-of-way held by UPRR. Substantially similar follow-on lawsuits were filed in federal courts by landowners in Nevada, Arizona and New Mexico. These suits, which were brought purportedly as class actions on behalf of all landowners who own land in fee adjacent to and underlying the railroad easement under which the SFPP pipeline is located in those respective states, asserted claims alleging that the defendants' occupation and use of the subsurface real property was improper. Plaintiffs' motions for class certification were denied by the federal courts in Arizona and California. The Ninth Circuit Court of Appeals denied interlocutory review of the class certification decisions, and the New Mexico and Nevada lawsuits were stayed. All pending lawsuits have now been settled or dismissed on terms that are not material to KMI's results of operations, cash flows or dividends to shareholders.

Gulf LNG Facility Arbitration

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Disagreement and Disputed Statements and 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. A three-member arbitration panel conducted an arbitration hearing in January 2017. On June 29, 2018, the arbitration panel delivered its Award, and the panel's ruling calls 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 Delaware Court of Chancery issued a Final Order and Judgment confirming the Award. 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 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. GLNG intends to vigorously prosecute and defend both lawsuits.

Brinckerhoff Merger Litigation

In April 2017, a purported class action suit was filed in the Delaware Court of Chancery by Peter Brinckerhoff, a former EPB unitholder on behalf of a class of former unaffiliated unitholders of EPB, seeking to challenge the $9.2 billion merger of EPB into a subsidiary of KMI as part of a series of transactions in November 2014 whereby KMI acquired all of the outstanding equity interests in KMP, Kinder Morgan Management, LLC and EPB that KMI and its subsidiaries did not already own. The suit alleged that the merger consideration did not sufficiently compensate EPB unitholders for the value of three derivative suits concerning drop down transactions which the derivative plaintiff lost standing to pursue after the merger. The suit claimed that the alleged failure to obtain sufficient merger consideration for the drop down lawsuits constituted a breach of the EPB limited partnership agreement and the implied covenant of good faith and fair dealing. The suit also asserted claims against KMI and certain individual defendants for allegedly tortiously interfering with and/or aiding and abetting the alleged breach of the limited partnership agreement. In November 2017, the Court dismissed the suit in its entirety. On June 8, 2018, the Delaware Supreme Court affirmed the dismissal. Also in November 2017, counsel for Brinckerhoff filed a separate lawsuit against KMEP and KMI seeking to recover up to $44 million in attorneys' fees allegedly incurred in connection with the assertion of derivative claims that Brinckerhoff lost standing to pursue. On April 9, 2018, the Court dismissed the suit in its entirety, and that dismissal is final.

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. Several of the cases were previously settled or dismissed, except for two cases pending in a U.S. District Court in Nevada, including a lawsuit brought by an industrial consumer in Kansas in which approximately $500 million in damages plus interest was alleged against all defendants, and a Wisconsin class action in which approximately $300 million in damages plus interest has been alleged against all defendants. The Kansas case has now been settled, and a settlement in principal has been reached in the Wisconsin class action that will require class notice and court approval in 2019. The amount to be paid in settlement of these matters is not material to our results of operations, cash flows or dividends to shareholders.

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, 2018 and 2017, our total reserve for legal matters was $207 million and $350 million, respectively. The reduction in the reserve primarily resulted from the payment of refunds in the EPNG rate case matter discussed above in "—FERC Proceedings—EPNG." The remaining reserve primarily relates to various claims from regulatory proceedings arising in our Products Pipelines business segment.

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 CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, 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 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 CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the EPA issued General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member. The LWG agreed to conduct the remedial investigation and feasibility study (RI/FS) leading to the proposed remedy for cleanup of the Portland Harbor site. The EPA issued the FS and the Proposed Plan on June 8, 2016 which included a proposed combination of dredging, capping, and enhanced natural recovery. On January 6, 2017, the EPA issued its Record of Decision (ROD) for the final cleanup plan. The final remedy is more stringent than the remedy proposed in the EPA’s Proposed Plan. The estimated cost increased from approximately $750 million to approximately $1.1 billion, and active cleanup is now expected to take as long as 13 years to complete. KMLT and 90 other parties are involved in a non-judicial allocation process to determine each party’s respective share of the cleanup costs. We are participating in the allocation process on behalf of KMLT and KMBT in connection with their current or former ownership or operation of four facilities located in Portland Harbor. Our share of responsibility for Portland Harbor Superfund Site costs will not be determined until the ongoing non-judicial allocation process is concluded in several years 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.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P., U.S. District Court, Arizona

The Roosevelt Irrigation District filed a lawsuit in 2010 against KMGP, KMEP and others under CERCLA for alleged contamination of the water purveyor’s wells. The First Amended Complaint sought $175 million in damages from approximately 70 defendants. KMGP was dismissed from the suit. On August 6, 2013, plaintiffs filed their Second Amended Complaint seeking monetary damages in unspecified amounts and reducing the number of defendants to 26 including KMEP and SFPP. The claims against KMEP and SFPP were related to alleged releases from a specific parcel within the SFPP Phoenix Terminal and the alleged impact of such releases on water wells owned by the plaintiffs and located in the vicinity of the Terminal. During the first quarter of 2018, KMEP and SFPP settled all claims made by the Roosevelt Irrigation District on terms that are not material to KMI’s results of operations, cash flows or dividends to shareholders.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately twenty 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 potentially responsible party 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 a radiological assessment of the surface 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. Defendants filed an answer and counterclaims seeking contribution and recovery of response costs allegedly incurred by the federal agencies in investigating uranium impacts on the Navajo Reservation. The counterclaim of defendant EPA has been settled, and no viable claims for reimbursement by the other defendants are known to exist. In August 2017, the District Court found the U.S. liable under CERCLA as owner of the Navajo Reservation. The matter seeking cost recovery and contribution from federal government agencies is set for trial in February 2019. We intend to continue to prosecute and defend this case vigorously.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, Essex, Hudson, Bergen and Passaic Counties, 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 Superfund Site (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be potentially responsible parties (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) 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 has entered into AOCs and is directing and funding the work required by the EPA. Under the first AOC, draft remedial investigation and feasibility studies (RI/FS) of the Site were submitted to the EPA in 2015, and EPA approval remains pending. Under the second AOC, the CPG members conducted a CERCLA removal action at the Passaic River Mile 10.9, and the group is currently conducting EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with the AOCs.

On April 11, 2014, the EPA announced the issuance of its Focused Feasibility Study (FFS) for the lower eight miles of the Passaic River Study Area, and its proposed plan for remedial alternatives to address the dioxin sediment contamination from the mouth of Newark Bay to River Mile 8.3. The EPA estimates the cost for the alternatives will range from $365 million to $3.2 billion. The EPA's preferred alternative would involve dredging the river bank-to-bank and installing an engineered cap at an estimated cost of $1.7 billion. On March 4, 2016, the EPA issued its Record of Decision (ROD) for the lower eight miles of the Passaic River Study area. The final cleanup plan in the ROD is substantially similar to the EPA's preferred alternative announced on April 11, 2014. 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 Passaic River. The design work is expected to take four years to complete and the cleanup is expected to take six years to complete. 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 Passaic River Study area. There remains significant uncertainty as to the implementation and associated costs of the remedy set forth in the FFS and ROD. There is also uncertainty as to the impact of the recent EPA FS directive for the upper nine mile segment not subject to the lower eight mile FFS and 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.

Plaquemines Parish Louisiana Coastal Zone Litigation

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 defendants' oil and gas exploration, production and transportation operations in the Bastian Bay, Buras, Empire and Fort Jackson oil and gas fields of Plaquemines Parish caused substantial damage to the coastal waters and nearby lands (Coastal Zone) within the Parish, including the erosion of marshes and the discharge of oil waste and other pollutants which detrimentally affected the quality of state waters and plant and animal life, in violation of the State and Local Coastal Resources Management Act of 1978 (Coastal Zone Management Act). The case is one of numerous similar cases pending in Louisiana. As a result of such alleged violations of the Coastal Zone Management Act, Plaquemines Parish seeks, among other relief, unspecified monetary relief, attorney fees, interest, and payment of costs necessary to restore the allegedly affected Coastal Zone to its original condition, including costs to clear, vegetate and detoxify the Coastal Zone. In connection with this suit, TGP made two tenders for defense and indemnity: (1) to Anadarko, as successor to the entity that purchased TGP's oil and gas assets in Bastian Bay, and (2) to Kinetica, which purchased TGP's pipeline assets in Bastian Bay in 2013. Anadarko accepted TGP's tender (limited to oil and gas assets), and Kinetica rejected TGP's tender. The Louisiana Department of Natural Resources (LDNR) and the Louisiana Attorney General (LAG) intervened in the lawsuit. The Court separated the defendants into several trial groups and set trials to begin in 2019. The case involving TGP was set for trial in 2020. During May 2018, the defendants removed numerous cases which allege violations under the Coastal Zone Management Act to federal court in Louisiana; the case involving TGP was removed to the U.S. District Court for the Eastern District of Louisiana. Thereafter, the defendants moved the U.S. Judicial Panel on Multidistrict Litigation to transfer all such cases, including the case involving TGP, to the U.S. District Court for the Eastern District of Louisiana for coordinated proceedings. On July 31, 2018, the Panel denied the motion. The plaintiffs and intervenors moved to remand all of the cases, including the case involving TGP, to the state district courts. Those motions are pending. All of the cases, including the case involving TGP, remain effectively stayed pending resolution of the removal and remand issues. We will continue to vigorously defend the lawsuit.

Vintage Assets, Inc. Coastal Erosion Litigation

On December 18, 2015, Vintage Assets, Inc. and several individual landowners filed a lawsuit in the State District Court for Plaquemines Parish, Louisiana alleging that its 5,000 acre property is composed of coastal wetlands, and that SNG and TGP failed to maintain pipeline canals and banks, causing widening of the canals, land loss, and damage to the ecology and hydrology of the marsh, in breach of right of way agreements, prudent operating practices, and Louisiana law. The suit also claims that defendants' alleged failure to maintain pipeline canals and banks constitutes negligence and has resulted in encroachment of the canals, constituting trespass. The suit seeks in excess of $80 million 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. The suit was removed to the U.S. District Court for the Eastern District of Louisiana. The SNG assets at issue were sold to Highpoint Gas Transmission, LLC in 2011, which was subsequently purchased by American Midstream Partners, LP. In response to SNG's demand for defense and indemnity, American Midstream Partners agreed to pay 50% of joint defense costs and expenses, with a percentage of indemnity to be determined upon final resolution of the suit. On October 20, 2016, plaintiffs filed an amended complaint naming Highpoint Gas Transmission, LLC as an additional defendant. A non-jury trial was held during September 2017. 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 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, Highpoint Gas Transmission, LLC 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 remanded the suit to the U.S. District Court for the Eastern District of Louisiana. In doing so, the Court of Appeals ordered the District Court to remand the suit to the State District Court of Plaquemines Parish, Louisiana for further proceedings. The District Court has not yet done so. We will continue to vigorously defend the suit.

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, 2018 and 2017, we have accrued a total reserve for environmental liabilities in the amount of $271 million and $279 million, respectively. In addition, as of both December 31, 2018 and 2017, we have recorded a receivable of $13 million for expected cost recoveries that have been deemed probable.

Other Contingencies

In 2017, in order to demonstrate to the NEB that Trans Mountain has sufficient financial resources to meet its responsibilities under Canada's Pipeline Safety Act (the "Act"), we entered into a loan facility with Trans Mountain pursuant to which it may borrow up to C$500 million from us in the event that a TMPL environmental incident occurs giving rise to a liability on the part of Trans Mountain under the Act. Upon the closing of the TMPL Sale on August 31, 2018, the government of Canada delivered to us a C$500 million cash-collateralized letter of credit to fully backstop our obligation under the loan facility, which will continue until the NEB approves a replacement arrangement with which Trans Mountain may satisfy its financial resources requirement.

19. Recent Accounting Pronouncements

Accounting Standards Updates

Topic 842

On February 25, 2016, the FASB issued ASU No. 2016-02, “Leases” followed by a series of related accounting standard updates (collectively referred to as “Topic 842”). Topic 842 establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures which are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and classification for existing leases upon adoption. We have also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows us to carry forward our historical accounting treatment for land easements on existing agreements upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements, and estimate approximately $500 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

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 to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in the more timely recognition of losses. ASU No. 2016-13 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU 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 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

ASU No. 2017-12

On August 28, 2017, the FASB issued ASU No. 2017-12, “Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities.” This 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. The guidance expands the ability to hedge nonfinancial and financial risk components, reduces complexity in fair value hedges of interest rate risk, eliminates the requirement to separately measure and report hedge ineffectiveness, and eases certain hedge effectiveness assessment requirements. ASU No. 2017-12 was effective January 1, 2019. We adopted ASU No. 2017-12 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 will be effective for us as of January 1, 2020, and earlier adoption is permitted. We are currently reviewing the effect of this ASU 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 each of the parent and subsidiary issuer in separate columns in this single set of condensed consolidating financial statements.

Excluding fair value adjustments, as of December 31, 2018, Parent Issuer and Guarantor, Subsidiary Issuer and Guarantor-KMP, and Subsidiary Guarantors had $15,192 million, $17,910 million, and $2,535 million of Guaranteed Notes outstanding, respectively. Included in the Subsidiary Guarantors debt balance as presented in the accompanying December 31, 2018 condensed consolidating balance sheet are approximately $159 million of capitalized lease debt that is 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, 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 expenses	(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 Taxes	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 Stockholders	$ 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 expenses	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 Taxes	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 Stockholders	$ 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 Statements of Income and Comprehensive Income
for the Year Ended December 31, 2016
(In Millions)

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - KMP	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Adjustments	Consolidated KMI
Total Revenues	$ 34	$ —	$ 11,572	$ 1,511	$ (59)	$ 13,058
Operating Costs, Expenses and Other						
Costs of sales	—	—	3,176	266	(13)	3,429
Depreciation, depletion and amortization	18	—	1,872	319	—	2,209
Other operating expenses	758	(36)	2,461	745	(46)	3,882
Total Operating Costs, Expenses and Other	776	(36)	7,509	1,330	(59)	9,520
Operating (Loss) Income	(742)	36	4,063	181	—	3,538
Other Income (Expense)						
Earnings from consolidated subsidiaries	2,948	2,802	245	58	(6,053)	—
Losses from equity investments	—	—	(113)	—	—	(113)
Interest, net	(696)	90	(1,149)	(51)	—	(1,806)
Amortization of excess cost of equity investments and other, net	33	—	(18)	4	—	19
Income Before Income Taxes	1,543	2,928	3,028	192	(6,053)	1,638
Income Tax Expense	(835)	(5)	(33)	(44)	—	(917)
Net Income	708	2,923	2,995	148	(6,053)	721
Net Income Attributable to Noncontrolling Interests	—	—	—	—	(13)	(13)
Net Income Attributable to Controlling Interests	708	2,923	2,995	148	(6,066)	708
Preferred Stock Dividends	(156)	—	—	—	—	(156)
Net Income Available to Common Stockholders	$ 552	$ 2,923	$ 2,995	$ 148	$ (6,066)	$ 552
Net Income	$ 708	$ 2,923	$ 2,995	$ 148	$ (6,053)	$ 721
Total other comprehensive (loss) income	(200)	(341)	(352)	55	638	(200)
Comprehensive income	508	2,582	2,643	203	(5,415)	521
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(13)	(13)
Comprehensive income attributable to controlling interests	$ 508	$ 2,582	$ 2,643	$ 203	$ (5,428)	$ 508

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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 Balance Sheet as of December 31, 2017
(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	$ 3	$ —	$ —	$ 262	$ (1)	$ 264
Other current assets - affiliates	6,214	5,201	22,402	858	(34,675)	—
All other current assets	243	59	1,938	235	(24)	2,451
Property, plant and equipment, net	236	—	31,093	8,826	—	40,155
Investments	665	—	6,498	135	—	7,298
Investments in subsidiaries	37,983	36,728	5,417	4,232	(84,360)	—
Goodwill	13,789	22	5,166	3,185	—	22,162
Notes receivable from affiliates	1,033	20,363	1,233	776	(23,405)	—
Deferred income taxes	3,635	—	—	—	(1,591)	2,044
Other non-current assets	254	164	4,080	183	—	4,681
Total assets	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055
LIABILITIES AND STOCKHOLDERS' EQUITY						
Liabilities						
Current portion of debt	$ 924	$ 975	$ 805	$ 124	$ —	$ 2,828
Other current liabilities - affiliates	13,225	14,188	6,512	750	(34,675)	—
All other current liabilities	468	347	2,055	508	(25)	3,353
Long-term debt	13,104	18,206	3,052	653	—	35,015
Notes payable to affiliates	2,009	448	20,593	355	(23,405)	—
Deferred income taxes	—	—	449	1,142	(1,591)	—
Other long-term liabilities and deferred credits	689	117	1,462	467	—	2,735
Total liabilities	30,419	34,281	34,928	3,999	(59,696)	43,931
Stockholders' equity						
Total KMI equity	33,636	28,256	42,899	14,693	(85,848)	33,636
Noncontrolling interests	—	—	—	—	1,488	1,488
Total stockholders' equity	33,636	28,256	42,899	14,693	(84,360)	35,124
Total liabilities and stockholders' equity	$ 64,055	$ 62,537	$ 77,827	$ 18,692	$ (144,056)	$ 79,055

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	—	—	—	2,998	—	2,998
Acquisitions of investments	—	—	(39)	—	—	(39)
Capital expenditures	(24)	—	(1,995)	(885)	—	(2,904)
Proceeds from sales of equity investments	—	—	124	—	—	124
Sales of property, plant and equipment, investments and other net assets, net of removal costs	9	—	(34)	5	—	(20)
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 parties	—	—	(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

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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

Condensed Consolidating Statements of Cash Flows
for the Year Ended December 31, 2016
(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	$ (3,981)	$ 4,943	$ 11,641	$ 885	$ (8,730)	$ 4,758
Cash flows from investing activities						
Acquisitions of assets and investments	(2)	—	(331)	—	—	(333)
Capital expenditures	(27)	—	(2,258)	(597)	—	(2,882)
Proceeds from sale of equity interests in subsidiaries, net	—	—	1,401	—	—	1,401
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	6	—	326	(2)	—	330
Contributions to investments	(343)	—	(54)	(11)	—	(408)
Distributions from equity investments in excess of cumulative earnings	2,417	298	190	—	(2,674)	231
Funding to affiliates	(2,820)	(535)	(5,062)	(727)	9,144	—
Loan repayments from related party	—	—	35	—	—	35
Other, net	—	—	3	(2)	—	1
Net cash used in investing activities	(769)	(237)	(5,750)	(1,339)	6,470	(1,625)
Cash flows from financing activities						
Issuances of debt	8,255	—	374	—	—	8,629
Payments of debt	(7,322)	(500)	(2,227)	(11)	—	(10,060)
Debt issue costs	(16)	—	(2)	(1)	—	(19)
Cash dividends - common shares	(1,118)	—	—	—	—	(1,118)
Cash dividends - preferred shares	(154)	—	—	—	—	(154)
Funding from affiliates	5,461	1,116	1,959	608	(9,144)	—
Contributions from parents	—	—	117	—	(117)	—
Contributions from noncontrolling interests	—	—	—	—	117	117
Distributions to parents	—	(5,286)	(6,116)	(73)	11,475	—
Distributions to noncontrolling interests	—	—	—	—	(24)	(24)
Other, net	(8)	—	—	—	—	(8)
Net cash provided by (used in) financing activities	5,098	(4,670)	(5,895)	523	2,307	(2,637)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	—	—	—	2	—	2
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	348	36	(4)	71	47	498
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	123	—	13	201	(48)	289
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 471	$ 36	$ 9	$ 272	$ (1)	$ 787

Supplemental Selected Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
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
2017				
Revenues	$3,424	$3,368	$ 3,281	$ 3,632
Operating Income	977	918	826	808
Net Income (Loss)	445	383	387	(992)
Net Income (Loss) Attributable to Kinder Morgan, Inc.	440	376	373	(1,006)
Net Income (Loss) Available to Common Stockholders	401	337	334	(1,045)
Basic and Diluted Earnings (Loss) Per Common Share	0.18	0.15	0.15	(0.47)

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
(principal financial and accounting officer)

Date: February 8, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAVID P. MICHELS David P. Michels	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 8, 2019
/s/ STEVEN J. KEAN Steven J. Kean	Chief Executive Officer (principal executive officer); Director	February 8, 2019
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 8, 2019
/s/ KIMBERLY A. DANG Kimberly A. Dang	President; Director	February 8, 2019
/s/ TED A. GARDNER Ted A. Gardner	Director	February 8, 2019
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 8, 2019
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 8, 2019
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 8, 2019
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 8, 2019
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 8, 2019
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 8, 2019
/s/ FAYEZ SAROFIM Fayez Sarofim	Director	February 8, 2019
/s/ C. PARK SHAPER C. Park Shaper	Director	February 8, 2019
/s/ WILLIAM A. SMITH William A. Smith	Director	February 8, 2019

/s/ JOEL V. STAFF Joel V. Staff	Director	February 8, 2019
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 8, 2019
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 8, 2019

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