



January 9, 2013

Maria Matoska
Arkansas Department of Environmental Quality
Waste Tire Program
5301 Northshore Drive
North Little Rock, Arkansas 72118

AFIN: 47-00987
Pmt #: 0029-SWTP
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To: MM-zyle

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RE: Kinder Morgan Bulk Terminals, Inc.
Barfield Terminal
P.O. Box 217
East End Highway #18
Armored, Arkansas 72310

Dear Ms. Matoska:

This letter is to provide you with additional information relating to ownership of the Barfield Terminal as required for a Waste Tire General Permit application.

Please be advised that the above referenced facility that is applying to the Arkansas Department of Environmental Quality for a Waste Tire General Permit is owned and operated by Kinder Morgan Bulk Terminals, Inc. (KMBT). KMBT is a subsidiary of Kinder Morgan Energy Partners, LP. Kinder Morgan Energy Partners, LP is a publicly traded company. Its audited financial statements include the assets and liabilities of KMBT.

KMBT is not required to file a disclosure statement pursuant to Arkansas Code Annotated Section 8-1-106, as it is a subsidiary of a publicly held company. Instead, we are submitting the most recent Form 10-K and 10-Q for Kinder Morgan Energy Partners, LP, as filed with the Securities and Exchange Commission.

If you have any questions, please contact the undersigned at 303-914-4634. Thank you for your attention to this matter.

Sincerely yours,

Nancy E. Van Burgel, Esq.
Assistant General Counsel
Kinder Morgan Energy Partners, LP

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

FORM 10-Q

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

For the quarterly period ended **September 30, 2012**

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: **1-11234**

KINDER MORGAN ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

76-0380342

(I.R.S. Employer
Identification No.)

500 Dallas Street, Suite 1000, Houston, Texas 77002

(Address of principal executive offices)(zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The Registrant had 246,381,091 common units outstanding as of October 29, 2012.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF INCOME (In Millions Except Per Unit Amounts) (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues				
Natural gas sales	\$ 675	\$ 925	\$ 1,756	\$ 2,575
Services	989	737	2,585	2,190
Product sales and other	669	449	1,791	1,201
Total Revenues	2,333	2,111	6,132	5,966
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	828	914	2,036	2,550
Operations and maintenance	429	399	1,094	1,163
Depreciation, depletion and amortization	292	247	796	685
General and administrative	131	100	379	387
Taxes, other than income taxes	63	37	169	133
Other expense (income)	(8)	(1)	(28)	(15)
Total Operating Costs, Expenses and Other	1,735	1,696	4,446	4,903
Operating Income	598	415	1,686	1,063
Other Income (Expense)				
Earnings from equity investments	100	52	225	155
Amortization of excess cost of equity investments	(1)	(2)	(5)	(5)
Interest expense	(184)	(134)	(480)	(396)
Interest income	8	6	19	16
Loss on remeasurement of previously held equity interest in KinderHawk to fair value (Note 2)	—	(167)	—	(167)
Other, net	4	3	14	11
Total Other Income (Expense)	(73)	(242)	(227)	(386)
Income from Continuing Operations Before Income Taxes	525	173	1,459	677
Income Tax (Expense) Benefit	(11)	(12)	(40)	(33)
Income from Continuing Operations	514	161	1,419	644
Discontinued Operations (Note 2)				
Income from operations of FTC Natural Gas Pipelines disposal group .	47	55	145	145
Loss from costs to sell and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value	(178)	—	(827)	—
Income (Loss) from Discontinued Operations	(131)	55	(682)	145
Net Income	383	216	737	789
Net Income Attributable to Noncontrolling Interests	(4)	(1)	(12)	(6)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	\$ 379	\$ 215	\$ 725	\$ 783
Calculation of Limited Partners' Interest in Net Loss				
Attributable to Kinder Morgan Energy Partners, L.P.:				
Income from Continuing Operations	\$ 509	\$ 161	\$ 1,400	\$ 640
Less: Pre-acquisition income from operations of drop-down asset group allocated to General Partner (Note 2)	(36)	—	(23)	—
Less: General Partner's remaining Interest	(367)	(298)	(1,024)	(870)
Limited Partners' Interest	106	(137)	353	(230)
Add: Limited Partners' Interest in Discontinued Operations	(128)	54	(668)	142
Limited Partners' Interest in Net Loss	\$ (22)	\$ (83)	\$ (315)	\$ (88)
Limited Partners' Net Income (Loss) per Unit:				
Income (Loss) from Continuing Operations	\$ 0.30	\$ (0.41)	\$ 1.02	\$ (0.71)
Income (Loss) from Discontinued Operations	(0.36)	0.16	(1.93)	0.44
Net Loss	\$ (0.06)	\$ (0.25)	\$ (0.91)	\$ (0.27)
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income (Loss) per Unit	356	331	345	323
Per Unit Cash Distribution Declared	\$ 1.26	\$ 1.16	\$ 3.69	\$ 3.45

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Income	\$ 383	\$ 216	\$ 737	\$ 789
Other Comprehensive Income (Loss):				
Change in fair value of derivatives utilized for hedging purposes	(90)	387	99	289
Reclassification of change in fair value of derivatives to net income.....	(10)	49	10	189
Foreign currency translation adjustments	70	(163)	68	(102)
Adjustments to pension and other postretirement benefit plan liabilities, net of tax.....	—	—	—	(13)
Total Other Comprehensive Income (Loss)	(30)	273	177	363
Comprehensive Income	353	489	914	1,152
Comprehensive Income Attributable to Noncontrolling Interests	(4)	(5)	(14)	(10)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	\$ 349	\$ 484	\$ 900	\$ 1,142

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions)

	September 30, 2012	December 31, 2011
ASSETS	(Unaudited)	
Current assets		
Cash and cash equivalents.....	\$ 532	\$ 409
Restricted deposits.....	6	—
Accounts, notes and interest receivable, net.....	956	884
Inventories.....	241	110
Gas in underground storage.....	56	62
Fair value of derivative contracts.....	59	72
Assets held for sale.....	1,859	—
Other current assets.....	59	39
Total Current assets.....	3,768	1,576
Property, plant and equipment, net.....	19,326	15,596
Investments.....	3,070	3,346
Notes receivable.....	168	165
Goodwill.....	4,605	1,436
Other intangibles, net.....	1,115	1,152
Fair value of derivative contracts.....	705	632
Deferred charges and other assets.....	836	200
Total Assets.....	\$ 33,593	\$ 24,103
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt.....	\$ 2,697	\$ 1,638
Cash book overdrafts.....	63	21
Accounts payable.....	849	706
Accrued interest.....	149	259
Accrued taxes.....	140	38
Deferred revenues.....	97	100
Fair value of derivative contracts.....	41	121
Accrued other current liabilities.....	526	236
Total Current liabilities.....	4,562	3,119
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding.....	15,217	11,183
Debt fair value adjustments.....	1,530	1,055
Total Long-term debt.....	16,747	12,238
Deferred income taxes.....	262	250
Fair value of derivative contracts.....	15	39
Other long-term liabilities and deferred credits.....	950	853
Total Long-term liabilities and deferred credits.....	17,974	13,380
Total Liabilities.....	22,536	16,499
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units.....	4,360	4,347
Class B units.....	18	42
i-units.....	3,492	2,857
General partner.....	2,856	259
Accumulated other comprehensive income.....	178	3
Total Kinder Morgan Energy Partners, L.P. Partners' Capital.....	10,904	7,508
Noncontrolling interests.....	153	96
Total Partners' Capital.....	11,057	7,604
Total Liabilities and Partners' Capital.....	\$ 33,593	\$ 24,103

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)
(Unaudited)

	Nine Months Ended September 30.	
	2012	2011
Cash Flows From Operating Activities		
Net Income.....	\$ 737	\$ 789
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	803	705
Amortization of excess cost of equity investments	5	5
Loss from costs to sell and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value (Note 2) .	827	—
Loss on remeasurement of previously held interest in Kinderhawk to fair value (Note 2)	—	167
Noncash compensation expense allocated from parent (Note 9)	—	90
Earnings from equity investments	(289)	(214)
Distributions from equity investments	277	201
Proceeds from termination of interest rate swap agreements	53	73
Changes in components of working capital:		
Accounts receivable	(40)	28
Inventories	(98)	9
Other current assets	13	(2)
Accounts payable	41	(9)
Cash book overdrafts	42	9
Accrued interest	(138)	(143)
Accrued taxes	74	47
Accrued liabilities	49	(2)
Rate reparations, refunds and other litigation reserve adjustments	(42)	161
Other, net	—	70
Net Cash Provided by Operating Activities	2,314	1,984
Cash Flows From Investing Activities		
Payment to KMI for drop-down asset group, net of cash acquired (Note 2)	(3,482)	—
Acquisitions of assets and investments	(72)	(945)
Repayments from related party	42	29
Capital expenditures	(1,273)	(838)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	36	29
(Investments in) Net proceeds from margin and restricted deposits	(16)	56
Contributions to equity investments	(155)	(297)
Distributions from equity investments in excess of cumulative earnings	120	165
Refined products, natural gas liquids and transmix line-fill	14	3
Other, net	—	1
Net Cash Used in Investing Activities	(4,786)	(1,797)
Cash Flows From Financing Activities		
Issuance of debt	8,378	6,356
Payment of debt	(5,074)	(5,538)
Debt issue costs	(16)	(17)
Proceeds from issuance of i-units	727	—
Proceeds from issuance of common units	387	813
Contributions from noncontrolling interests	40	15
Distributions to partners and noncontrolling interests:		
Common units	(847)	(762)
Class B units	(19)	(18)
General Partner	(970)	(859)
Noncontrolling interests	(23)	(20)
Other, net	(1)	—
Net Cash Provided by (Used in) Financing Activities	2,582	(30)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	13	(15)
Net increase in Cash and Cash Equivalents	123	142
Cash and Cash Equivalents, beginning of period	409	129
Cash and Cash Equivalents, end of period	\$ 532	\$ 271

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In Millions)
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
Noncash Investing and Financing Activities		
Net assets acquired by the transfer of the drop-down asset group.....	\$ 6,371	\$ —
Assets acquired or liabilities settled by the issuance of common units.....	\$ 686	\$ 24
Assets acquired by the assumption or incurrence of liabilities	\$ —	\$ 180
Contribution of net assets to investments	\$ —	\$ 8
Sale of investment ownership interest in exchange for note.....	\$ —	\$ 4
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	\$ 586	\$ 510
Cash paid during the period for income taxes	\$ 16	\$ 9
The accompanying notes are an integral part of these consolidated financial statements.		

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to “we,” “us,” “our,” “KMP” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We own an interest in or operate approximately 53,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described further in Note 8). Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals, and handle such products as ethanol, coal, petroleum coke and steel. We are also the leading producer and transporter of carbon dioxide, commonly called CO₂, for enhanced oil recovery projects in North America. Our general partner is owned by Kinder Morgan, Inc., as discussed below.

Kinder Morgan, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation and referred to as KMI in this report, indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation; however, in July 2007, our general partner issued and sold to a third party 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC.

On February 29, 2012, Kinder Morgan Kansas, Inc., a Kansas corporation, merged with and into its parent, Kinder Morgan Holdco DE Inc., a Delaware corporation and a wholly-owned subsidiary of KMI. Immediately following this merger, Kinder Morgan Holdco DE Inc. (the surviving legal entity from the merger) then merged with and into its parent KMI. KMI's common stock trades on the New York Stock Exchange under the symbol “KMI.” As of September 30, 2012, KMI and its consolidated subsidiaries owned, through KMI's general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 13% interest in us.

On May 25, 2012, KMI acquired all of the outstanding shares of El Paso Corporation (referred to as EP in this report) in a transaction that created one of the largest energy companies in the United States.

On March 15, 2012, KMI announced that it had reached an agreement with the U.S. Federal Trade Commission (FTC) to divest certain of our assets in order to receive regulatory approval for its proposed EP acquisition. Subject to final FTC approval, KMI agreed to sell our (i) Kinder Morgan Interstate Gas Transmission natural gas pipeline system; (ii) Trailblazer natural gas pipeline system; (iii) Casper and Douglas natural gas processing operations; and (iv) 50% equity investment in the Rockies Express natural gas pipeline system. In this report, we refer to this combined group of assets as our FTC Natural Gas Pipelines disposal group.

Prior to KMI's announcement, we included the assets we are required to sell pursuant to the FTC's order in our Natural Gas Pipelines business segment. Because this combined group of assets, including our equity investment in Rockies Express, has its own operations and cash flows, we now report this FTC Natural Gas Pipelines disposal group as a business held for sale. We expect to complete the sale of our FTC Natural Gas Pipelines disposal group in November 2012. For more information about this planned divestiture, see both “—Basis of Presentation” below and Note 2 “Acquisitions and Discontinued Operations—FTC Natural Gas Pipelines Disposal Group - Discontinued Operations.”

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval

of our general partner. KMR's shares representing limited liability company interests trade on the New York Stock Exchange under the symbol "KMR."

More information about the entities referred to above and the delegation of control agreement is contained in our Annual Report on Form 10-K for the year ended December 31, 2011 and in our Current Report on Form 8-K filed May 1, 2012. In this report, we refer to our Annual Report on Form 10-K for the year ended December 31, 2011 as our 2011 Form 10-K.

Basis of Presentation

We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. These rules and regulations conform to the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America and referred to in this report as the Codification. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with the Codification. We believe, however, that our disclosures are adequate to make the information presented not misleading.

Our accompanying consolidated financial statements reflect normal adjustments, and also recurring adjustments that are, in the opinion of our management, necessary for a fair statement of our financial results for the interim periods, and certain amounts from prior periods have been reclassified to conform to the current presentation. Interim results are not necessarily indicative of results for a full year; accordingly, you should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C\$. Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation.

Our financial statements are consolidated into the consolidated financial statements of KMI; however, except for the related party transactions described in Note 9 "Related Party Transactions—Asset Acquisitions," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

Following KMI's March 15, 2012 announcement of its intention to sell the assets that comprise our FTC Natural Gas Pipelines disposal group (described above in "—Kinder Morgan, Inc. and Kinder Morgan G.P., Inc."), we accounted for the disposal group as discontinued operations in accordance with the provisions of the "Presentation of Financial Statements—Discontinued Operations" Topic of the Codification. Accordingly, we (i) reclassified and excluded the FTC Natural Gas Pipelines disposal group's results of operations from our results of continuing operations and reported the disposal group's results of operations separately as "Income from operations of FTC Natural Gas Pipelines disposal group" within the discontinued operations section of our accompanying consolidated statements of income for all periods presented; (ii) separately reported a "Loss from costs to sell and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value" within the discontinued operations section of our accompanying consolidated statements of income for the three and nine months ended September 30, 2012; and (iii) reclassified and reported the disposal group's combined assets within "Assets held for sale" in our accompanying consolidated balance sheet as of September 30, 2012.

Because the disposal group's combined liabilities were not material to our consolidated balance sheet, we included the disposal group's liabilities within "Accrued other current liabilities" in our accompanying consolidated balance sheet as of September 30, 2012. In addition, we did not elect to present separately the operating, investing and financing cash flows related to the disposal group in our accompanying consolidated statements of cash flows. For more information about the discontinued operations of our FTC Natural Gas Pipelines disposal group, see Note 2 "Acquisitions and Discontinued Operations—FTC Natural Gas Pipelines Disposal Group - Discontinued Operations."

Limited Partners' Net Income (Loss) per Unit

We compute Limited Partners' Net Income (Loss) per Unit by dividing our limited partners' interest in net income (loss) by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners' Net Income (Loss) per Unit are made in accordance with the "Earnings per Share" Topic of the Codification.

2. Acquisitions and Discontinued Operations

El Paso Midstream Investment Company, LLC

Effective June 1, 2012, we acquired from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. (together with its affiliates, referred to as KKR) a 50% ownership interest in El Paso Midstream Investment Company, LLC, a joint venture that owns (i) the Altamont natural gas gathering, processing and treating assets located in the Uinta Basin in Utah; and (ii) the Camino Real natural gas and oil gathering system located in the Eagle Ford shale formation in South Texas. We acquired our equity interest for an aggregate consideration of \$289 million in common units (we issued 3,792,461 common units and determined each unit's value based on the \$76.23 closing market price of the common units on the New York Stock Exchange on the June 4, 2012 issuance date). A subsidiary of KMI owns the remaining 50% interest in the joint venture.

We account for our investment under the equity method of accounting, and our investment and our pro rata share of the joint venture's operating results are included as part of our Natural Gas Pipelines business segment. As of September 30, 2012, our net equity investment in the joint venture totaled \$301 million and is included within "Investments" on our accompanying consolidated balance sheet.

August 2012 KMI Asset Drop-Down

Effective August 1, 2012, we acquired the full ownership interest in the Tennessee Gas natural gas pipeline system and a 50% ownership interest in the El Paso Natural Gas pipeline system from KMI for an aggregate consideration of approximately \$6.2 billion. In this report, we refer to this acquisition of assets from KMI as the drop-down transaction; the combined group of assets acquired from KMI as the drop-down asset group; the Tennessee Gas natural gas pipeline system or Tennessee Gas Pipeline L.L.C. as TGP, and the El Paso Natural Gas pipeline system or El Paso Natural Gas Pipeline LLC as EPNG.

We purchased the drop-down asset group from KMI in order to replace the cash flows associated with the FTC Natural Gas Pipelines disposal group that we will divest. Our consideration to KMI consisted of (i) \$3.5 billion in cash; (ii) 4,667,575 common units (valued at \$0.4 billion based on the \$81.52 closing market price of the common units on the New York Stock Exchange on the August 13, 2012 issuance date); and (iii) \$2.3 billion in assumed debt (consisting of the combined carrying value of 100% of TGP's debt borrowings and 50% of EPNG's debt borrowings as of August 1, 2012, excluding any debt fair value adjustments). The terms of the drop-down transaction were approved on behalf of KMI by the independent members of its board of directors and on our behalf by the audit committees and the boards of directors of both our general partner and KMR, in its capacity as the delegate of our general partner, following the receipt by the independent directors of KMI and the audit committees of our general partner and KMR of separate fairness opinions from different independent financial advisors.

KMI acquired the drop-down asset group as part of its acquisition of EP on May 25, 2012 (discussed above in Note 1). Pursuant to current accounting principles in conformity with the Codification, KMI accounted for its acquisition of the drop-down asset group under the purchase accounting method, and we accounted for the drop-down transaction as a transfer of net assets between entities under common control. Accordingly, we prepared our consolidated financial statements and the related financial information contained in this report to reflect the transfer of net assets from KMI to us as if such transfer had taken place on May 25, 2012. Specifically, we (i) recognized the acquired assets and assumed liabilities at KMI's carrying value as of its acquisition date, May 25, 2012 (including all of KMI's purchase accounting adjustments); (ii) recognized any difference between our purchase price and the carrying value of the net assets we acquired as an adjustment to our Partners' Capital (specifically, as an adjustment to our general partner's capital interests); and (iii) retrospectively adjusted our consolidated financial statements, for any date after KMI's May 25, 2012 acquisition of EP, to reflect our results on a consolidated combined basis including the results of the drop-down asset group as of or at the beginning of the respective period.

Additionally, because KMI both controls us and consolidates our financial statements into its consolidated financial statements as a result of its ownership of our general partner, we fully allocated the earnings of the drop-down asset group for the period beginning May 25, 2012 and ending August 1, 2012 to our general partner and we reported this amount separately as “Pre-acquisition income from operations of drop-down asset group allocated to General Partner” within the Calculation of Limited Partners’ Interest in Net Loss section of our accompanying consolidated statements of income for the three and nine months ended September 30, 2012. For all periods beginning after our acquisition date of August 1, 2012, we allocated our earnings (including the earnings from the drop-down asset group) to all of our partners according to our partnership agreements. For more information on the changes to our Partners’ Capital related to the drop-down transaction, see Note 5 “Partners’ Capital—Changes in Partners’ Capital.”

TGP is a 13,900 mile pipeline system with a transport design capacity of approximately 7.5 billion cubic feet per day of natural gas. It transports natural gas from Louisiana, the Gulf of Mexico and south Texas to the northeastern United States, including the metropolitan areas of New York City and Boston. EPNG is a 10,200 mile pipeline system with a design capacity of approximately 5.6 billion cubic feet per day of natural gas. It transports natural gas from the San Juan, Permian and Anadarko basins to California, other western states, Texas and northern Mexico. Combined, the two pipeline systems have more than 200 billion cubic feet of working natural gas storage capacity.

The drop-down asset group is included in our Natural Gas Pipelines reportable business segment. We account for our 100% ownership interest in TGP under the consolidation method and we account for our 50% investment in EPNG under the equity method of accounting. As of September 30, 2012, our net equity investment in EPNG totaled \$870 million and is included within “Investments” on our accompanying consolidated balance sheet.

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the nine months ended September 30, 2012 and 2011, assumes that the drop-down transaction had occurred as of January 1, 2011. We have prepared these unaudited pro forma financial results for comparative purposes only. These unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed the drop-down transaction as of January 1, 2011 or the results that will be attained in the future. Amounts presented below are in millions, except for the per unit amounts:

	Pro Forma Nine Months Ended September 30,	
	2012	2011
	(Unaudited)	
Revenues	\$ 6,549	\$ 6,640
Income from Continuing Operations	\$ 1,396	\$ 844
Income (Loss) from Discontinued Operations	\$ (682)	\$ 145
Net Income	\$ 714	\$ 989
Net Income Attributable to Noncontrolling Interests	\$ (12)	\$ (8)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	\$ 702	\$ 981
Limited Partners’ Net Income (Loss) per Unit:		
Income (Loss) from Continuing Operations	\$ 0.82	\$ (0.19)
Income (Loss) from Discontinued Operations	(1.89)	0.43
Net Income (Loss)	<u>\$ (1.07)</u>	<u>\$ 0.24</u>

FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

As described above in Note 1 “General—Basis of Presentation,” in March 2012, we began accounting for our FTC Natural Gas Pipelines disposal group as discontinued operations. We had previously remeasured the disposal group in the first half of 2012 to reflect our initial assessment of its fair value as a result of the FTC mandated sale requirement, and based on additional information gained in the sale process during the current quarter, we recognized additional loss amounts from fair value remeasurement and sales liability adjustments. For the nine months ended September 30, 2012, we recognized a combined \$827 million non-cash loss from both remeasurement and estimated costs to sell, and we

reported this loss amount separately as “Loss from costs to sell and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value” within the discontinued operations section of our accompanying consolidated statement of income for the nine months ended September 30, 2012.

We also reclassified the fair value of the disposal group’s assets and included this fair value amount within “Assets held for sale” in our accompanying consolidated balance sheet as of September 30, 2012 (because the disposal group’s combined liabilities were not material to our consolidated balance sheet as of this date, we included the disposal group’s liabilities within “Accrued other current liabilities.”) Our “Assets held for sale” are primarily comprised of property, plant and equipment, and our investment in the Rockies Express natural gas pipeline system.

Summarized financial information for the disposal group is as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenues.....	\$ 71	\$ 83	\$ 204	\$ 241
Operating expenses	(45)	(42)	(116)	(136)
Depreciation and amortization	—	(7)	(7)	(20)
Other expense.....	(1)	—	(1)	—
Earnings from equity investments	22	21	64	59
Interest income and Other, net	—	1	1	2
Income tax (expense) benefit.....	—	(1)	—	(1)
Earnings from discontinued operations	<u>\$ 47</u>	<u>\$ 55</u>	<u>\$ 145</u>	<u>\$ 145</u>

KinderHawk Field Services LLC

Effective July 1, 2011, we acquired from Petrohawk Energy Corporation the remaining 50% equity ownership interest in KinderHawk Field Services LLC (KinderHawk) that we did not already own. Following our acquisition of the remaining ownership interest, we changed our method of accounting from the equity method to full consolidation, and due to us acquiring a controlling financial interest in KinderHawk, we remeasured our previous 50% equity investment in KinderHawk to its fair value. We recognized a \$167 million non-cash loss as a result of this remeasurement, and we reported this loss separately within the “Other Income (Expense)” section in our accompanying consolidated statements of income for the three and nine months ended September 30, 2011. For additional information regarding our July 2011 KinderHawk acquisition, see Note 3 “Acquisitions and Divestitures” to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

3. Goodwill

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes, but combined with Products Pipelines for presentation in the table below); (iii) Natural Gas Pipelines; (iv) CO₂; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2012 impairment test, and no event indicating an impairment has occurred subsequent to that date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for the nine months ended September 30, 2012 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO ₂	Terminals	Kinder Morgan Canada	Total
Historical Goodwill	\$ 263	\$ 557	\$ 46	\$ 326	\$ 621	\$ 1,813
Accumulated impairment losses(a)	—	—	—	—	(377)	(377)
Balance as of December 31, 2011	263	557	46	326	244	1,436
Acquisitions(b)	—	3,246	—	—	—	3,246
Disposals(c)	—	(85)	—	—	—	(85)
Currency translation adjustments	—	—	—	—	8	8
Balance as of September 30, 2012	<u>\$ 263</u>	<u>\$ 3,718</u>	<u>\$ 46</u>	<u>\$ 326</u>	<u>\$ 252</u>	<u>\$ 4,605</u>

- (a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of U.S. generally accepted accounting principles, the consideration of this transaction caused KMI to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, KMI recorded a goodwill impairment charge of \$377 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment is now included in our accumulated impairment losses.
- (b) Acquisition amount relates to our August 1, 2012 acquisition of the drop-down asset group from KMI as discussed in Note 2.
- (c) Amount represents reclassification of FTC Natural Gas Pipelines disposal group's goodwill to "Assets held for sale." Since our FTC Natural Gas Pipelines disposal group represents a significant portion of our Natural Gas Pipelines business segment, we allocated the goodwill of the segment based on the relative fair value of the portion being disposed of and the portion of the segment remaining.

4. Debt

The following table summarizes the net carrying value of our outstanding debt, excluding our debt fair value adjustments, as of September 30, 2012 and December 31, 2011 (in millions):

	September 30, 2012	December 31, 2011
Current portion of debt(a)	\$ 2,697	\$ 1,638
Long-term portion of debt	15,217	11,183
Net carrying value of debt(b)	<u>\$ 17,914</u>	<u>\$ 12,821</u>

- (a) As of September 30, 2012 and December 31, 2011, includes commercial paper borrowings of \$2,664 million and \$645 million, respectively.
- (b) Excludes debt fair value adjustments. As of September 30, 2012 and December 31, 2011, our "Debt fair value adjustments" increased our debt balances by \$1,530 million and \$1,055 million, respectively. In addition to normal adjustments associated with valuing our debt obligations equal to the present value of amounts to be paid determined at appropriate current interest rates, our debt fair value adjustments also include (i) the value of our interest rate swap agreements; and (ii) any unamortized portion of proceeds received from the early termination of interest rate swap agreements.

Changes in our outstanding debt, excluding debt fair value adjustments, during the nine months ended September 30, 2012 are summarized as follows (in millions):

Debt borrowings	Interest rate	Increase / (decrease)	Cash received / (paid)
Issuances and Assumptions			
Senior notes due September 1, 2022(a)	3.95%	\$ 1,000	\$ 998
Senior notes due February 15, 2023(b)	3.45%	625	622
Senior notes due August 15, 2042(b)	5.00%	625	621
Commercial paper	variable	5,561	5,561
Bridge loan credit facility due February 6, 2013(c)	variable	576	576
Tennessee Gas Pipeline L.L.C. - senior notes due February 1, 2016(d)	8.00%	250	—
Tennessee Gas Pipeline L.L.C. - senior notes due April 4, 2017(d)	7.50%	300	—
Tennessee Gas Pipeline L.L.C. - senior notes due March 15, 2027(d)	7.00%	300	—
Tennessee Gas Pipeline L.L.C. - senior notes due October 15, 2028(d)	7.00%	400	—
Tennessee Gas Pipeline L.L.C. - senior notes due June 15, 2032(d)	8.375%	240	—
Tennessee Gas Pipeline L.L.C. - senior notes due April 1, 2037(d)	7.625%	300	—
Total increases in debt		<u>\$ 10,177</u>	<u>\$ 8,378</u>
Repayments and other			
Senior notes due March 15, 2012(a)	7.125%	\$ (450)	\$ (450)
Senior notes due September 15, 2012(e)	5.85%	(500)	(500)
Commercial paper	variable	(3,542)	(3,542)
Bridge loan credit facility due February 6, 2013(c)	variable	(576)	(576)
Kinder Morgan Texas Pipeline, L.P. - senior notes due January 2, 2014	5.23%	(5)	(5)
Kinder Morgan Arrow Terminals L.P. - note due April 4, 2014	6.0%	(1)	(1)
Kinder Morgan Operating L.P. "A" - BP note due March 31, 2012	5.40%	(5)	—
Kinder Morgan Canada Company - BP note due March 31, 2012	5.40%	(5)	—
Total decreases in debt		<u>\$ (5,084)</u>	<u>\$ (5,074)</u>

- (a) On March 14, 2012, we completed a public offering of \$1.0 billion in principal amount of 3.95% senior notes due September 1, 2022. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of \$994 million, and we used the proceeds both to repay our \$450 million 7.125% senior notes that matured on March 15, 2012 and to reduce the borrowings under our commercial paper program.
- (b) On August 13, 2012, we completed a public offering of \$1,250 million in principal amount of senior notes in two separate series, consisting of \$625 million of 3.45% notes due February 15, 2023 and \$625 million of 5.00% notes due August 15, 2042. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of \$1,236 million, and we used the proceeds to pay a portion of the purchase price for the drop-down transaction.
- (c) On August 6, 2012, we entered into a second credit agreement with us as borrower; Wells Fargo Bank, National Association, as administrative agent; Barclays Bank PLC, as syndication agent; and a syndicate of other lenders. This credit agreement provided for borrowings up to \$2.0 billion pursuant to a short-term bridge loan credit facility with a term of six months. The covenants of this facility are substantially similar to the covenants of our existing senior unsecured revolving credit facility that is due July 1, 2016, and similar to our existing credit facility, borrowings under this bridge loan credit facility may be used to back our commercial paper issuances and for other general partnership purposes (including to pay a portion of the purchase price for the drop-down transaction). In August 2012, we made borrowings of \$576 million under our short-term bridge loan credit facility to pay a portion of the purchase price for the drop-down transaction. We then repaid these credit facility borrowings in August 2012 with incremental borrowings under our commercial paper program, and as of September 30, 2012, our bridge loan credit facility was not drawn on.

The size of our bridge loan credit facility will be reduced by an amount equal to the net cash proceeds of certain debt and equity issuances in excess of \$1.65 billion, and as of September 30, 2012, our bridge loan credit facility was reduced to allow for maximum borrowings of \$1.685 billion. We are also required to prepay borrowings under this credit facility with net proceeds received from certain debt and equity issuances and from the expected divestiture of our FTC Natural Gas Pipelines disposal

group. All such prepayments will automatically reduce the borrowing capacity of the credit facility. In addition, in conjunction with the establishment of this short-term bridge loan credit facility, we increased our commercial paper program to provide for the issuance of up to \$3.885 billion of commercial paper (up from \$2.2 billion).

- (d) Our subsidiary, Tennessee Gas Pipeline L.L.C. is the obligor of six separate series of fixed-rate unsecured senior notes having a combined principal amount of \$1,790 million. We assumed these debt borrowings as part of the drop-down transaction.
- (e) On September 15, 2012, we paid \$500 million to retire the principal amount of our 5.85% senior notes that matured on that date.

We had, as of September 30, 2012, approximately \$1.0 billion of combined borrowing capacity available under our two separate unsecured credit facilities. As of this date, the combined \$3,885 million amount available for borrowing under our two credit facilities was reduced by a combined amount of \$2,886 million, consisting of \$2,664 million of commercial paper borrowings and \$222 million of letters of credit, consisting of (i) a \$100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined \$86 million in three letters of credit that support tax-exempt bonds; (iii) a \$12 million letter of credit that supports debt securities issued by the Express pipeline system; and (iv) a combined \$24 million in other letters of credit supporting other obligations of us and our subsidiaries.

For additional information regarding our debt facilities and for information on our contingent debt agreements, see Note 8 "Debt" and Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

5. Partners' Capital

Limited Partner Units

As of September 30, 2012 and December 31, 2011, our Partners' Capital included the following limited partner units:

	September 30, 2012	December 31, 2011
Common units.....	246,111,590	232,677,222
Class B units.....	5,313,400	5,313,400
i-units.....	113,276,125	98,509,389
Total limited partner units	<u>364,701,115</u>	<u>336,500,011</u>

The total limited partner units represent our limited partners' interest and an effective 98% interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its right to receive incentive distributions.

As of September 30, 2012, (i) KMI and its consolidated affiliates (excluding our general partner) held 19,314,003 common units; (ii) our general partner held 1,724,000 common units; (iii) a wholly-owned subsidiary of KMI held all of our Class B units; and (iv) KMR held all of our i-units. As of December 31, 2011, (i) KMI and its consolidated affiliates (excluding our general partner) held 14,464,428 common units; (ii) our general partner held 1,724,000 common units; (iii) a wholly-owned subsidiary of KMI held all of our Class B units; and (iv) KMR held all of our i-units. Our Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange. Our i-units are a separate class of limited partner interests in us and are not publicly traded. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units.

Changes in Partners' Capital

For each of the nine month periods ended September 30, 2012 and 2011, changes in the carrying amounts of our Partners' Capital attributable to both us and our noncontrolling interests, including our comprehensive income are summarized as follows (in millions):

	Nine Months Ended September 30,					
	2012			2011		
	KMP	Noncontrolling Interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	\$ 7,508	\$ 96	\$ 7,604	\$ 7,211	\$ 82	\$ 7,293
Units issued for cash	1,114	—	1,114	813	—	813
Units issued as consideration in the acquisition of assets	686	—	686	24	—	24
Distributions paid in cash	(1,836)	(23)	(1,859)	(1,639)	(20)	(1,659)
Adjustments to capital due to acquisitions from KMI(a)	2,483	25	2,508	—	—	—
Contribution from KMI for FTC Natural Gas Pipelines disposal group selling expenses(b)	45	—	45	—	—	—
Noncash compensation expense allocated from KMI(c)	—	—	—	89	1	90
Cash contributions.....	—	40	40	—	15	15
Other adjustments	4	1	5	(3)	—	(3)
Comprehensive income.....	900	14	914	1,142	10	1,152
Ending Balance	<u>\$ 10,904</u>	<u>\$ 153</u>	<u>\$ 11,057</u>	<u>\$ 7,637</u>	<u>\$ 88</u>	<u>\$ 7,725</u>

- (a) Amounts relate to the drop-down transaction, described in Note 2. We determined that the drop-down transaction constituted a transfer of net assets between entities under common control, and accordingly, we recognized the assets we acquired and the liabilities we assumed at KMI's carrying value (including all purchase accounting adjustments from KMI's acquisition of the drop-down asset group from EP effective May 25, 2012). We then recognized the difference between our purchase price and the carrying value of the assets acquired and liabilities assumed as an adjustment to our Partners' Capital. As of September 30, 2012, the carrying value of the assets we acquired and the liabilities we assumed totaled \$6,371 million. We paid to KMI \$3,482 million in cash, issued to KMI 4,667,575 common units valued at \$381 million, and recognized a non-cash increase of \$2,508 million in our Partners' Capital. The increase to Partners' Capital consisted of a \$2,483 million increase in our general partner's 1% general partner capital interest in us, and a \$25 million increase in our general partner's 1.0101% general partner capital interest in our subsidiary Kinder Morgan Operating L.P. "A" (a noncontrolling interest to us).
- (b) For further information about this contribution, see Note 9.
- (c) For further information about this expense, see Note 9. We do not have any obligation, nor do we expect to pay any amounts related to this expense.

During each of the nine month periods ended September 30, 2012 and 2011, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On February 27, 2012, we entered into a third amended and restated equity distribution agreement with UBS Securities LLC (UBS) which increased the aggregate offering price of our common units to up to \$1.9 billion (up from \$1.2 billion). During the three and nine months ended September 30, 2012, we issued 1,357,946 and 4,772,741, respectively, of our common units pursuant to our equity distribution agreement with UBS. We received net proceeds of \$110 million and \$387 million, respectively, from the issuance of these common units and we used the proceeds to reduce the borrowings under our commercial paper program. For additional information regarding our equity distribution agreement, see Note 10 to our consolidated financial statements included in our 2011 Form 10-K.

For the nine month period ended September 30, 2012, in addition to the issuance of common units pursuant to our equity distribution agreement, our significant equity issuances consisted of the following:

- on June 4, 2012, we issued 3,792,461 common units as our purchase price for the 50% equity ownership interest in El Paso Midstream Investment Company, LLC we acquired from KKR. For more information about this acquisition, see Note 2 "Acquisitions and Discontinued Operations—El Paso Midstream Investment Company, LLC;"
- in August 2012, in connection with the drop-down transaction, we issued 4,667,575 of our common units to KMI. We valued the units at \$381 million, based on the \$81.52 closing market price of the common units on the New

York Stock Exchange on August 13, 2012. For more information on the drop-down transaction, see Note 2 "Acquisitions and Discontinued Operations—August 2012 KMI Asset Drop-Down;" and

- in the third quarter of 2012, KMR issued 10,120,000 of its shares in a public offering at a price of approximately \$73.50 per share, less commissions and underwriting expenses. KMR used the net proceeds received from the issuance of these 10,120,000 shares to buy additional i-units from us, and we received net proceeds of \$727 million. We used the proceeds to pay a portion of the purchase price for the drop-down transaction.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed, and we determine the allocation of incentive distributions to our general partner by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement.

On August 14, 2012, we paid a cash distribution of \$1.23 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended June 30, 2012. KMR, our sole i-unitholder, received a distribution of 1,578,616 i-units from us on August 14, 2012, based on the \$1.23 per unit distributed to our common unitholders on that date. The distributions were declared on July 18, 2012, payable to unitholders of record as of July 31, 2012.

On August 12, 2011, we paid a cash distribution of \$1.15 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended June 30, 2011. KMR, our sole i-unitholder, received a distribution of 1,701,916 i-units from us on August 12, 2011, based on the \$1.15 per unit distributed to our common unitholders on that date. The distributions were declared on July 20, 2011, payable to unitholders of record as of August 1, 2011.

Our general partner's incentive distribution that we paid in August 2012 and August 2011 (for the quarterly periods ended June 30, 2012 and 2011, respectively) was \$337 million and \$293 million, respectively. The increased incentive distribution to our general partner paid for the second quarter of 2012 over the incentive distribution paid for the second quarter of 2011 reflects the increase in the amount distributed per unit as well as an increase in the number of common units and i-units outstanding. Each of these two incentive distributions were reduced from what they would have been, however, by waived incentive amounts equal to \$7 million related to common units issued to finance our acquisition of KinderHawk (we acquired an initial 50% ownership interest in KinderHawk in May 2010 and the remaining 50% interest in July 2011). To support our KinderHawk acquisition, our general partner agreed to waive certain incentive distribution amounts beginning with the distribution payments we made for the quarterly period ended June 30, 2010, and ending with the distribution payments we make for the quarterly period ended March 31, 2013.

For additional information about our 2011 partnership distributions, see Notes 10 and 11 to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

Subsequent Events

In early October 2012, we issued 269,501 of our common units for the settlement of sales made on or before September 30, 2012 pursuant to our equity distribution agreement. We received net proceeds of \$22 million from the issuance of these 269,501 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On October 17, 2012, we declared a cash distribution of \$1.26 per unit for the quarterly period ended September 30, 2012. The distribution will be paid on November 14, 2012 to unitholders of record as of October 31, 2012. Our common unitholders and our Class B unitholder will receive cash. KMR will receive a distribution of 1,842,210 additional i-units based on the \$1.26 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.016263) will be issued. This fraction was determined by dividing:

- \$1.26, the cash amount distributed per common unit

by

- \$77.478, the average of KMR's shares' closing market prices from October 15-26, 2012, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

6. Risk Management

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

Energy Commodity Price Risk Management

As of September 30, 2012, we had entered into the following outstanding commodity forward contracts to hedge our forecast energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil	(20.5) million barrels
Natural gas fixed price	(27.6) billion cubic feet
Natural gas basis	(27.6) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas fixed price	(0.6) billion cubic feet

As of September 30, 2012, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2016.

Interest Rate Risk Management

As of September 30, 2012, we had a combined notional principal amount of \$5,525 million of fixed-to-variable interest rate swap agreements, effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of London InterBank Offered Rate (LIBOR) plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of September 30, 2012, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

As of December 31, 2011, we had a combined notional principal amount of \$5,325 million of fixed-to-variable interest rate swap agreements. In March 2012, (i) we entered into four additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of \$500 million, effectively converting a portion of the interest expense associated with our 3.95% senior notes due September 1, 2022 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread; and (ii) two separate fixed-to-variable interest rate swap agreements having a combined notional principal amount of \$200 million and converting a portion of the interest expense associated with our 7.125% senior notes terminated upon the maturity of the associated notes. In addition, (i) in June 2012, we terminated an existing fixed-to-variable interest rate swap agreement having a notional amount of \$100 million, and we received proceeds of \$53 million from the early termination of this swap agreement; (ii) in August 2012, we entered into an additional fixed-to-variable interest rate swap agreement having a notional principal amount of \$100 million, effectively converting a portion of the interest expense associated with our 3.45% senior notes due February 15, 2023 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread; and (iii) in September 2012, a fixed-to-variable interest rate swap agreement

having a combined notional principal amount of \$100 million and effectively converting a portion of the interest expense associated with our 5.85% senior notes terminated upon the maturity of the associated notes.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as “Fair value of derivative contracts” in the respective sections of our accompanying consolidated balance sheets, or, as of September 30, 2012 only, included within “Assets held for sale.” The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of September 30, 2012 and December 31, 2011 (in millions):

Fair Value of Derivative Contracts					
		Asset derivatives		Liability derivatives	
		September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Balance sheet location		Fair value	Fair value	Fair value	Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	\$ 58	\$ 66	\$ (39)	\$ (116)
	Current-Assets held for Sale / Accrued other current liabilities	1	—	—	—
	Non-current-Fair value of derivative contracts	52	39	(15)	(39)
Subtotal		111	105	(54)	(155)
Interest rate swap agreements	Current-Fair value of derivative contracts	—	3	—	—
	Non-current-Fair value of derivative contracts	652	593	—	—
Subtotal		652	596	—	—
Total		763	701	(54)	(155)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	1	3	(2)	(5)
	Non-current-Fair value of derivative contracts	1	—	—	—
Total		2	3	(2)	(5)
Total derivatives		<u>\$ 765</u>	<u>\$ 704</u>	<u>\$ (56)</u>	<u>\$ (160)</u>

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within “Debt fair value adjustments” on our accompanying consolidated balance sheets. Our “Debt fair value adjustments” also include all unamortized debt discount/premium amounts and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of September 30, 2012, we had a combined unamortized debt premium amount of \$378 million, and as of December 31, 2011, we had a combined debt discount amount of \$24 million. As of September 30, 2012 and December 31, 2011, the unamortized premium from the termination of interest rate swap agreements totaled \$500 million and \$483 million, respectively, and as of September 30, 2012, the weighted average amortization period for this premium was approximately 18 years.

Effect of Derivative Contracts on the Income Statement

The following two tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the three and nine months ended September 30, 2012 and 2011 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivatives	Amount of gain/(loss) recognized in income on derivatives and related hedged item			
		Three Months Ended		Nine Months Ended September 30,	
		2012	2011	2012	2011
Interest rate swap agreements	Interest expense	\$ 28	\$ 437	\$ 109	\$ 501
Total		\$ 28	\$ 437	\$ 109	\$ 501
Fixed rate debt	Interest expense	\$ (28)	\$ (437)	\$ (109)	\$ (501)
Total		\$ (28)	\$ (437)	\$ (109)	\$ (501)

- (a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt, which exactly offset each other as a result of no hedge ineffectiveness.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)(a)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended September 30,			Three Months Ended September 30,			Three Months Ended September 30,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contract	\$ (90)	\$ 387	Revenues-Natural gas sales	\$ 2	\$ —	Revenues-Natural gas sales	\$ —	\$ —
			Revenues-Product sales and other	—	(51)	Revenues-Product sales and other	(5)	8
			Gas purchases and other costs of sales	8	2	Gas purchases and other costs of sales	—	—
Total	\$ (90)	\$ 387	Total	\$ 10	\$ (49)	Total	\$ (5)	\$ 8
	Nine Months Ended September 30,			Nine Months Ended September 30,			Nine Months Ended September 30,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contract	\$ 99	\$ 289	Revenues-Natural gas sales	\$ 4	\$ 1	Revenues-Natural gas sales	\$ —	\$ —
			Revenues-Product sales and other	(31)	(203)	Revenues-Product sales and other	(8)	10
			Gas purchases and other costs of sales	17	13	Gas purchases and other costs of sales	—	—
Total	\$ 99	\$ 289	Total	\$ (10)	\$ (189)	Total	\$ (8)	\$ 10

- (a) We expect to reclassify an approximate \$25 million gain associated with energy commodity price risk management activities and included in our Partners' Capital as of September 30, 2012 into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.
- (b) No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, the amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred).

For each of the three and nine months ended September 30, 2012 and 2011, we recognized no material gain or loss in income from derivative contracts not designated as hedging contracts.

Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our over-the-counter swaps and options are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

The maximum potential exposure to credit losses on our derivative contracts as of September 30, 2012 was (in millions):

	Asset position
Interest rate swap agreements	\$ 652
Energy commodity derivative contracts	113
Gross exposure	765
Netting agreement impact.....	(39)
Cash collateral held	—
Net exposure.....	<u>\$ 726</u>

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of both September 30, 2012 and December 31, 2011, we had no outstanding letters of credit supporting our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. As of September 30, 2012, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling \$6 million, and we reported this amount as "Restricted deposits" in our accompanying consolidated balance sheet. As of December 31, 2011, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling \$10 million, and we reported this amount within "Accrued other current liabilities" in our accompanying consolidated balance sheet.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. As of September 30, 2012, we estimate that if our credit rating was downgraded one notch, we would be required to post no additional collateral to our counterparties. If we were downgraded two notches (that is, below investment grade), we would be required to post \$8 million of additional collateral.

7. 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; and (ii) interest rate swap agreements as of September 30, 2012 and December 31, 2011, based on the three levels established by the Codification. The fair values of our current and non-current asset and liability derivative contracts each reported separately as "Fair value of derivative contracts" in the respective sections of our accompanying consolidated balance sheets, or, as of September 30, 2012 only, included within "Assets held for sale." The fair value measurements in the tables below do not include cash margin deposits made by us or our counterparties, which are reported within "Restricted deposits" and "Accrued other current liabilities," respectively, in our accompanying consolidated balance sheets (in millions).

		Asset fair value measurements using			
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	
		Total			
As of September 30, 2012					
Energy commodity derivative contracts(a)	\$	113	\$ 16	\$ 88	\$ 9
Interest rate swap agreements	\$	652	\$ —	\$ 652	\$ —

As of December 31, 2011					
Energy commodity derivative contracts(a)	\$	108	\$ 34	\$ 47	\$ 27
Interest rate swap agreements	\$	596	\$ —	\$ 596	\$ —

		Liability fair value measurements using			
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	
		Total			
As of September 30, 2012					
Energy commodity derivative contracts(a)	\$	(56)	\$ (14)	\$ (39)	\$ (3)
Interest rate swap agreements	\$	—	\$ —	\$ —	\$ —
As of December 31, 2011					
Energy commodity derivative contracts(a)	\$	(160)	\$ (15)	\$ (125)	\$ (20)
Interest rate swap agreements	\$	—	\$ —	\$ —	\$ —

- (a) Level 1 consists primarily of the New York Mercantile Exchange (NYMEX) natural gas futures. Level 2 consists primarily of over-the-counter (OTC) West Texas Intermediate swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of West Texas Intermediate options.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the three and nine months ended September 30, 2012 and 2011 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended		Nine Months Ended September 30,	
	2012	2011	2012	2011
Derivatives-net asset (liability)				
Beginning of Period	\$ 20	7	\$ 7	\$ 19
Total gains or (losses):				
Included in earnings	(3)	3	(3)	6
Included in other comprehensive income	(6)	37	—	21
Purchases	—	—	3	5
Settlements	(5)	(2)	(1)	(6)
End of Period	<u>\$ 6</u>	<u>45</u>	<u>\$ 6</u>	<u>\$ 45</u>
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date.....				
	<u>\$ (5)</u>	<u>\$ 3</u>	<u>\$ (1)</u>	<u>\$ 4</u>

As of September 30, 2012, we reported our West Texas Intermediate options at fair value using Level 3 inputs due to such derivatives not having observable market prices. We determined the fair value of our West Texas Intermediate options using the Black Scholes option valuation methodology after giving consideration to a range of factors, including the prices at which the options were acquired, local market conditions, implied volatility, and trading values on public exchanges.

The significant unobservable input we use to measure the fair value of our Level 3 derivatives is implied volatility of options. We obtain the implied volatility of our West Texas Intermediate options from a third party service provider. As of September 30, 2012, this volatility ranged from 30% – 31% based on both historical market data and future estimates of market fluctuation. Significant increases (decreases) in this input in isolation would result in a significantly lower (higher) fair value measurement.

Fair Value of Financial Instruments

The estimated fair value of our outstanding debt balance as of September 30, 2012 and December 31, 2011 (both short-term and long-term), is disclosed below (in millions):

	September 30, 2012		December 31, 2011	
	Carrying Value	Estimated Fair value	Carrying Value	Estimated Fair value
Total debt	\$ 19,444	\$ 20,748	\$ 13,876	\$ 14,238

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both September 30, 2012 and December 31, 2011.

8. Reportable Segments

We divide our operations into five reportable business segments. These segments and their principal sources of revenues are as follows:

- Products Pipelines—the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids;
- Natural Gas Pipelines—the sale, transport, processing, treating, storage and gathering of natural gas;
- CO₂—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;
- Terminals—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals; and
- Kinder Morgan Canada—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States.

We evaluate performance principally based on each segment's earnings before depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third party debt costs and interest expense, unallocable interest income, and unallocable 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 maker organizes their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

Financial information by segment follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues				
Products Pipelines				
Revenues from external customers	\$ 386	\$ 242	\$ 940	\$ 695
Natural Gas Pipelines				
Revenues from external customers	1,113	1,093	2,699	2,999
CO ₂				
Revenues from external customers	420	372	1,250	1,063
Terminals				
Revenues from external customers	334	327	1,017	979
Intersegment revenues.....	—	1	1	1
Kinder Morgan Canada				
Revenues from external customers	80	77	226	230
Total segment revenues.....	2,333	2,112	\$ 6,133	5,967
Less: Total intersegment revenues.....	—	(1)	(1)	(1)
Total consolidated revenues.....	\$ 2,333	\$ 2,111	\$ 6,132	\$ 5,966

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines(b).....	\$ 150	\$ 103	\$ 492	\$ 304
Natural Gas Pipelines(c)	405	18	877	319
CO ₂	327	295	988	823
Terminals	183	180	565	525
Kinder Morgan Canada.....	56	48	158	150
Total segment earnings before DD&A	1,121	644	3,080	2,121
Total segment depreciation, depletion and amortization.....	(292)	(247)	(796)	(685)
Total segment amortization of excess cost of investments.....	(1)	(2)	(5)	(5)
General and administrative expenses(d)	(131)	(100)	(379)	(387)
Interest expense, net of unallocable interest income	(181)	(132)	(474)	(393)
Unallocable income tax expense	(2)	(2)	(7)	(7)
Income (Loss) from discontinued operations(e)	(131)	55	(682)	145
Total consolidated net income.....	\$ 383	\$ 216	\$ 737	\$ 789

	September 30, 2012	December 31, 2011
Assets		
Products Pipelines.....	\$ 4,775	\$ 4,479
Natural Gas Pipelines	16,479	9,958
CO ₂	2,297	2,147
Terminals	4,869	4,428
Kinder Morgan Canada.....	1,866	1,827
Total segment assets	30,286	22,839
Corporate assets(f)	1,448	1,264
Assets held for sale(g)	1,859	—
Total consolidated assets.....	\$ 33,593	\$ 24,103

- (a) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).
- (b) Three and nine month 2012 amounts include increases in expense of \$9 million associated with rate case liability adjustments. Three and nine month 2011 amounts include increases in expense of \$69 million and \$234 million, respectively, associated with rate case, leased rights-of-way, and other legal liability adjustments.
- (c) Three and nine month 2011 amounts include a \$167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk to fair value (discussed further in Note 2).
- (d) Nine month 2011 amount includes an \$87 million increase in expense allocated to us from KMI and associated with a one-time special cash bonus payment that was paid to non-senior management employees in May 2011; however, we do not have any obligation, nor did we pay any amounts related to this expense.
- (e) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. Three and nine month 2012 amounts include loss amounts of \$178 million and \$827 million, respectively, from both the remeasurement of net assets to fair value and estimated costs to sell (discussed further in Note 2).
- (f) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to debt fair value adjustments.
- (g) Primarily represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

9. Related Party Transactions

Notes Receivable

Plantation Pipe Line Company

We and ExxonMobil have a term loan agreement covering a note receivable due from Plantation Pipe Line Company. We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was \$50 million as of both September 30, 2012 and December 31, 2011. The note bears interest at the rate of 4.25% per annum and provides for semiannual payments of principal and interest on December 31 and June 30 each year, with a final principal payment of \$45 million (for our portion of the note) due on July 20, 2016. We included \$1 million of our note receivable balance within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of both September 30, 2012 and December 31, 2011, and we included the remaining outstanding balance within "Notes receivable."

Express US Holdings LP

We own a 33 1/3% equity ownership interest in the Express pipeline system. We also hold a long-term investment in a C\$114 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. The debenture (i) is denominated in Canadian dollars; (ii) is due in full on January 9, 2023; (iii) bears interest at the rate of 12.0% per annum; and (iv) provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year. As of September 30, 2012 and December 31, 2011, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was \$116 million and \$112 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

KMI and El Paso Corporation

At the time of KMI's acquisition of EP on May 25, 2012 (discussed in Note 1), TGP had a note receivable from EP, and during the second quarter of 2012, TGP received combined principal note repayments of approximately \$44 million. Upon our acquisition of TGP from KMI on August 1, 2012 (as part of the drop-down transaction discussed in Note 2), we and KMI agreed that the remaining \$466 million amount due on the note receivable would not be repaid. Accordingly, this amount was treated as a decrease in KMI's investment in TGP and us, and as a result, TGP no longer has a related party note receivable with either KMI or EP. However, because we have included the historical results of TGP as though the net assets had been transferred to us May 25, 2012, the \$44 million repayment is now included within "Repayments from related party" on our consolidated statement of cash flows for the nine months ended September 30, 2012.

Other Receivables and Payables

As of September 30, 2012 and December 31, 2011, our related party receivables (other than the notes receivable discussed above in "—Notes Receivable") totaled \$32 million and \$26 million, respectively. The September 30, 2012 receivables amount consisted of (i) \$30 million included within "Accounts, notes and interest receivable, net" on our accompanying consolidated balance sheet; and (ii) \$2 million of natural gas imbalance receivables included within "Other current assets." The \$30 million receivable amount consisted primarily of a net receivable amount due from KMI (including a \$45 million receivable amount discussed below in "—FTC Natural Gas Pipelines Disposal Group Selling Expenses") and the Express pipeline system. The \$2 million natural gas imbalance receivable consisted primarily of amounts due from Natural Gas Pipeline Company of America LLC, a 20%-owned equity investee of KMI and referred to in this report as NGPL.

The December 31, 2011 receivables amount consisted of \$15 million included within "Accounts, notes and interest receivable, net," and \$11 million of natural gas imbalance receivables included within "Other current assets." The \$15 million receivable amount primarily consisted of amounts due from the Express pipeline system, NGPL, and KMI. The \$11 million natural gas imbalance receivable consisted of amounts due from both NGPL and Rockies Express Pipeline LLC.

As of September 30, 2012, our related party payables totaled \$3 million and we included these amounts within "Accounts payable" on our accompanying consolidated balance sheets. This amount consisted primarily of \$2 million in payables due to two of our equity method investees. The December 31, 2011 related party payables totaled \$1 million.

At both balance sheet dates, our related party payables included a \$1 million amount we owed to the noncontrolling partner of Globalplex Partners, a Louisiana joint venture owned 50% and controlled by us.

Asset Acquisitions

In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; (ii) TransColorado Gas Transmission Company LLC from KMI in November 2004; and (iii) TGP and 50% of EPNG from KMI in August 2012, KMI agreed to indemnify us and our general partner with respect to approximately \$3.8 billion of our debt. KMI would be obligated to perform under this indemnity only if we are unable, and/or our assets were insufficient, to satisfy our obligations.

In addition, KMI has indemnified us and our general partner with respect to approximately \$558 million for our proportionate 50% share of EPNG's debt. Because we account for our investment in EPNG under the equity method of accounting, we do not include its debt in the debt reported on our accompanying consolidated balance sheets.

Non-Cash Compensation Expenses

In the first nine months of 2011, KMI allocated to us certain non-cash compensation expenses totaling \$90 million; however, we do not have any obligation, nor did we pay any amounts related to these compensation expenses. The amount included an \$87 million expense associated with a one-time special cash bonus payment that was paid by KMI to non-senior management employees in May 2011, and a \$3 million expense related to KMI's going-private transaction in May 2007. Since we were not responsible for paying these expenses, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet.

FTC Natural Gas Pipelines Disposal Group Selling Expenses

In the third quarter of 2012, we recognized an estimated \$78 million selling expense (and an associated liability) related to the divestiture of our FTC Natural Gas Pipelines disposal group. We expect to pay the liability associated with this expense in the fourth quarter of 2012. Furthermore, KMI agreed to contribute \$45 million to us to be used as partial funding for this liability payment, and accordingly, we recognized a \$45 million receivable from KMI and an associated increase to our Partners' Capital (specifically, an increase to our general partner's capital interest in us).

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a duty to manage us in a manner beneficial to our unitholders. Our general partner owns all of KMR's voting securities and elects all of KMR's directors. KMI indirectly owns all the common stock of our general partner, and the officers of KMI have fiduciary duties to manage KMI, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to the owners of KMI. Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us.

The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of duty. The partnership agreements also provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of KMI may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand.

For a more complete discussion of our related party transactions, including (i) the accounting for our general and administrative expenses; (ii) KMI's operation and maintenance of the assets comprising our Natural Gas Pipelines business segment; and (iii) our partnership interests and distributions, see Note 11 to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

10. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the nine months ended September 30, 2012. Additional information with respect to these proceedings can be found in Note 16 to our consolidated financial statements that were included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012. This note also contains a description of any material legal proceedings that were initiated against us during the nine months ended September 30, 2012, and a description of any material events occurring subsequent to September 30, 2012, but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calneve Pipe Line LLC as Calneve; Chevron Products Company as Chevron; BP West Coast Products, LLC as BP; ConocoPhillips Company (now Phillips 66 Company) as Phillips 66; Tesoro Refining and Marketing Company as Tesoro; Western Refining Company, L.P. as Western Refining; Navajo Refining Company, L.L.C. as Navajo; Holly Refining & Marketing Company LLC (now HollyFrontier Refining & Marketing LLC) as HollyFrontier; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc. (now Delta Air Lines, Inc.), Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Tennessee Gas Pipeline L.L.C. as TGP; our subsidiary Kinder Morgan CO₂ Company, L.P. (the successor to Shell CO₂ Company, Ltd.) as Kinder Morgan CO₂; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the American Railway Engineering and Maintenance-of-Way Association as AREMA; Severstal Sparrows Point, LLC as Severstal; RG Steel Sparrows Point LLC as RG Steel; the Texas Commission of Environmental Quality as the TCEQ; The Premcor Refining Group, Inc. as Premcor; Port Arthur Coker Company as PACC; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order as an NOPV; the federal Comprehensive Environmental Response, Compensation and Liability Act as CERCLA; the United States Environmental Protection Agency as the U.S. EPA; the United States Environmental Protection Agency's Suspension and Debarment Division as the U.S. EPA SDD; the New Jersey Department of Environmental Protection as the NJDEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Liquids Terminals LLC as KMLT; our subsidiary Kinder Morgan Interstate Gas Transmission LLC as KMIGT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. "OR" dockets designate complaint proceedings, and "IS" dockets designate protest proceedings.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing 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: (i) whether "substantially changed circumstances" have occurred with respect to any "grandfathered" rates under the Energy Policy Act of 1992 such that those rates could be challenged; (ii) whether indexed rate increases are justified; and (iii) the appropriate level of return and income tax allowance we may include in our rates.

SFPP

The following FERC dockets are currently pending:

- FERC Docket No. IS08-390 (West Line Rates) (Opinion Nos. 511 and 511-A)-Protestants: BP, ExxonMobil, Phillips 66, Valero Marketing, Chevron, the Airlines-Status: FERC order issued on December 16, 2011 (Opinion No. 511-A). While the order made certain findings that were adverse to SFPP, it ruled in favor of SFPP on many significant issues. SFPP made a compliance filing at the end of January 2012, and our rates reflect this filing. SFPP also filed a rehearing request on certain adverse rulings in the FERC order. Petitions for review of Opinion Nos. 511 and 511-A have been filed at the D.C. Circuit and are held in abeyance pending a ruling on SFPP's

request for rehearing. It is not possible to predict the outcome of FERC review of the rehearing request or appellate review;

- FERC Docket No. IS09-437 (East Line Rates)-Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, Western Refining, Navajo, HollyFrontier, and Southwest Airlines-Status: Opinion and Order on Initial Decision, Opinion No. 522, issued on September 20, 2012. The FERC generally made findings favorable to SFPP on significant issues and consistent with FERC's Opinion Nos. 511 and 511-A. Requests for rehearing, if any, must be filed in October 2012. It is not possible to predict the outcome of FERC review of any request for rehearing or appellate review of this order;
- FERC Docket No. IS11-444 (2011 West Line Index Rate Increases)-Protestants: BP, ExxonMobil, Phillips 66, Valero Marketing, Chevron, the Airlines, Tesoro, Western Refining, Navajo, and HollyFrontier-Status: The shippers filed a motion for summary disposition that was granted in the shippers' favor in an initial decision issued on March 16, 2012. SFPP filed a brief with the FERC taking exception to the initial decision. The FERC will review the initial decision, and it is not possible to predict the outcome of FERC or appellate review;
- FERC Docket Nos. IS12-390 (SFPP East Line Index Rates)/IS12-388 and IS12-501 (SFPP West Line Index Rates)-Protestants: the Airlines, BP, Chevron, HollyFrontier, Phillips 66, Tesoro, Valero Marketing, and Western Refining-Status: Collectively, these shippers protested SFPP's index-based rate increases for its East Line (IS12-390) and West Line (IS12-388 and IS12-501). FERC rejected the protests against SFPP's East Line rate increases and accepted the protests against SFPP's West Line rate increases (IS12-388). Following FERC acceptance of the West Line protests, SFPP withdrew these rate increases, and FERC terminated the IS12-388 proceeding. SFPP subsequently made a new filing to increase its West Line rates by a smaller index-based percentage (IS12-501), which FERC accepted notwithstanding shipper protests. Shippers requested rehearing of FERC's acceptance of the East Line and West Line rate increases, and those requests are pending before FERC. It is not possible to predict the outcome of FERC or appellate review;
- FERC Docket Nos. IS12-388/IS12-500 (SFPP West Line Index Rates)-Protestants: the Airlines, BP, Chevron, Phillips 66, Tesoro, Valero Marketing-Status: These shippers protested SFPP's index-based rate increases for its West Line. Following FERC acceptance of the protests, SFPP withdrew these rate increases and subsequently increased its West Line rates by a smaller percentage that FERC found acceptable as to SFPP's East Line in IS12-390. Shippers may protest SFPP's new West Line index filing, and it is not possible to predict the outcome of further FERC review, if any;
- FERC Docket No. OR11-13 (SFPP Base Rates)—Complainant: Phillips 66—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Phillips 66 permitted to amend its complaint based on additional data;
- FERC Docket No. OR11-16 (SFPP Base Rates)—Complainant: Chevron—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Chevron permitted to amend its complaint based on additional data; and
- FERC Docket No. OR11-18 (SFPP Base Rates)—Complainant: Tesoro—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Tesoro permitted to amend its complaint based on additional data.

With respect to all of the SFPP proceedings above, we estimate that the shippers are seeking approximately \$20 million in annual rate reductions and approximately \$100 million in refunds. However, applying the principles of Opinion Nos. 511, 511-A, 522, as applicable, to pending cases would result in substantially lower rate reductions and refunds than those sought by the shippers. We do not expect refunds in these cases to have an impact on our distributions to our limited partners.

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On March 17, 2011, the FERC issued an order consolidating and setting for hearing the complaints in Docket Nos. OR07-7, OR07-18, OR07-19, OR07-22, OR09-15, and OR09-20 filed by Tesoro, the Airlines, BP, Chevron, Phillips 66 and Valero Marketing. A settlement agreement resolving these proceedings was filed on February 24, 2012 and was

certified to the FERC on March 1, 2012. On April 3, 2012, the FERC approved the settlement, and in May 2012, after the rates reduced by the settlement became effective, we made settlement payments of \$54 million.

California Public Utilities Commission Proceedings

We have previously reported ratemaking and complaint proceedings against SFPP pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services. These matters have been consolidated and assigned to two administrative law judges.

On May 26, 2011, the CPUC issued a decision in several intrastate rate cases involving SFPP and a number of its shippers (the “Long” cases). The decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance, allocation of environmental expenses, and refund liability which we believe are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. On March 8, 2012, the CPUC issued another decision related to the Long cases. This decision largely reflected the determinations made on May 26, 2011, including the denial of an income tax allowance for SFPP. The CPUC's order denied SFPP's request for rehearing of the CPUC's income tax allowance treatment, while granting requested rehearing of various other issues relating to SFPP's refund liability and staying the payment of refunds until resolution of the outstanding issues on rehearing. On March 23, 2012, SFPP filed a petition for writ of review in the California Court of Appeals including, among other things, a review of the CPUC's determination that SFPP is not entitled to recover an income tax allowance in its intrastate rates. In October 2012, the Court agreed to hear an appeal on the merits of the issues appealed.

On April 6, 2012, in proceedings unrelated to the above-referenced CPUC dockets, a CPUC administrative law judge issued a proposed decision substantially reducing SFPP's authorized cost of service and ordering SFPP to pay refunds from May 24, 2007 to the present of revenues collected in excess of the authorized cost of service. The proposed decision was subsequently withdrawn, and the presiding administrative law judge is expected to reissue a proposed decision at some indeterminate time in the future. On January 30, 2012, SFPP filed an application reducing its intrastate rates by approximately 7%. This matter remains pending before the CPUC.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately \$375 million in reparation payments and approximately \$30 million in annual rate reductions. The actual amount of reparations will be determined through further proceedings at the CPUC and, potentially, the California Court of Appeals. We believe that the appropriate application of the income tax allowance and corrections of errors in law and fact should result in a considerably lower amount. We do not expect any reparations that we would pay in these matters to have an impact on our distributions to our limited partners.

Carbon Dioxide Tax Assessments

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to our subsidiary Kinder Morgan CO₂. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO₂ with respect to carbon dioxide produced from the McElmo Dome unit for tax years 2005, 2006, and 2007. The total amount of tax assessed was \$6 million, plus interest of \$1 million and penalties of \$2 million. Kinder Morgan CO₂ protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO₂ is now awaiting the Colorado Department of Revenue's response to the protest.

Montezuma County, Colorado Property Tax Assessment

In November of 2009, the County Treasurer of Montezuma County, Colorado, issued to Kinder Morgan CO₂, as operator of the McElmo Dome unit, retroactive tax bills for tax year 2008, in the amount of \$2 million. Of this amount, 37.2% is attributable to Kinder Morgan CO₂'s interest. The retroactive tax bills were based on the assertion that a portion of the actual value of the carbon dioxide produced from the McElmo Dome unit was omitted from the 2008 tax roll due to an alleged overstatement of transportation and other expenses used to calculate the net taxable value. Kinder Morgan CO₂ paid the retroactive tax bills under protest and filed petitions for a refund of the taxes paid under protest. On February 6, 2012, the Montezuma County Board of County Commissioners denied the refund petitions, and we appealed to the Colorado Board of Assessment Appeals. A hearing on this matter will be held in the first quarter of 2013.

Other

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO₂'s payments on carbon dioxide produced from the McElmo Dome and Bravo Dome units are currently ongoing. These audits and inquiries involve federal agencies, the states of Colorado and New Mexico, and county taxing authorities in the state of Colorado.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and UPRR are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (*Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.*, Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In September 2011, the judge determined that the annual rent payable as of January 1, 2004 was \$15 million, subject to annual consumer price index increases. SFPP intends to appeal the judge's determination, but if that determination is upheld, SFPP would owe approximately \$75 million in back rent. Accordingly, during 2011, we increased our rights-of-way liability to cover this liability amount. In addition, the judge determined that UPRR is entitled to an estimated \$20 million for interest on the outstanding back rent liability. We believe the award of interest is without merit and we are pursuing our appellate rights.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP appealed this decision, and in December 2008, the appellate court affirmed the decision. In addition, UPRR contends that SFPP must comply with the more expensive AREMA standards in determining when relocations are necessary and in completing relocations. Each party is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. A trial occurred in the fourth quarter of 2011, with a verdict having been reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. SFPP is evaluating its post-trial and appellate options.

Since SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position, our results of operations, our cash flows, and our distributions to our limited partners. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal and located in Sparrows Point, Maryland collapsed while being operated by KMBT. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the United States District Court for the District of Maryland, Case No. 09CV1668-WMN. Severstal and its successor in interest, RG Steel, allege that KMBT was contractually obligated to replace the collapsed crane and that its employees were negligent in failing to properly secure the crane prior to the collapse. RG Steel seeks to recover in excess of \$30 million for the alleged value of the crane and lost profits. KMBT denies each of RG Steel's allegations. On or about June 1, 2012, RG Steel filed for bankruptcy in Case No. 12-11669 in the United States Bankruptcy Court for the District of Delaware; consequently, the trial date has been postponed indefinitely.

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.

Perth Amboy, New Jersey Tank Release

In May 2011, the PHMSA issued an NOPV to KMLT. The notice alleges violations of PHMSA's regulations related to an October 28, 2009 tank release from our Perth Amboy, New Jersey liquids terminal. No product left the company's property, and additionally, there were no injuries, no impact to the adjacent community or public, and no fire as a result of the release. The notice proposes a penalty of less than \$1 million. KMLT is pursuing an administrative appeal of the NOPV.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and were no injuries associated with the incident. We immediately began clean up operations in coordination with federal, state and local agencies. The cause of the incident is outside force damage. The incident is under investigation by the PHMSA, U.S. EPA and the Florida Department of Environmental Protection.

General

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is reasonably possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date and the reserves we have established, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. As of September 30, 2012 and December 31, 2011, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of \$309 million and \$332 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

New Jersey Department of Environmental Protection v. Occidental Chemical Corporation, et al. (Defendants), Maxus Energy Corp. and Tierra Solutions, Inc. (Third Party Plaintiffs) v. 3M Company et al., Superior Court of New Jersey, Law Division – Essex County, Docket No. L-9868-05

The NJDEP sued Occidental Chemical and others under the New Jersey Spill Act for contamination in the Newark Bay Complex including numerous waterways and rivers. Occidental et al. then brought in approximately 300 third party defendants for contribution. NJDEP claimed damages related to forty years of discharges of TCDD (a form of dioxin), DDT and "other hazardous substances." GATX Terminals Corporation (n/k/a/ KMLT) was brought in as a third party defendant because of the noted hazardous substances language and because the Carteret, New Jersey facility (a former GATX Terminals facility) is located on the Arthur Kill River, one of the waterways included in the litigation. This case was filed against third party defendants in 2009. The judge issued his trial plan for this case during the first quarter of 2011. According to the trial plan, the judge allowed the State to file summary judgment motions against Occidental, Maxus and Tierra on liability issues immediately. Numerous third party defendants, as part of a joint defense group of which KMLT is a member, filed motions to dismiss, which were denied, and now have filed interim appeals from those motions. The appeals court panel heard oral arguments on these motions to dismiss in March 2012 and issued a ruling denying these motions in June 2012. The appellants have filed appeals to the New Jersey Supreme Court regarding this lower court ruling. Maxus/Tierra's claims against the third party defendants are set to be tried in April 2013 with damages to be tried in September 2013.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the U.S. EPA sent out 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. The major potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member and pays a minimal fee to be part of the group. The LWG agreed to conduct the Remedial Investigation and Feasibility Study leading to the proposed remedy for cleanup of the Portland Harbor site. Once the U.S. EPA determines the cleanup remedy from the remedial investigations and feasibility studies conducted during the last decade at the site, it will issue a Record of Decision. Currently, KMLT and 90 other parties are involved in an allocation process to determine each party's respective share of the cleanup costs. This is a non-judicial allocation process. We are participating in the allocation process on behalf of both KMLT and KMBT. Each entity has two facilities located in Portland Harbor. We expect the allocation to conclude in 2013 or 2014, depending upon when the U.S. EPA issues its Record of Decision.

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

This is a CERCLA case brought against a number of defendants by a water purveyor whose wells have allegedly been contaminated due to the presence of a number of contaminants. The Roosevelt Irrigation District is seeking up to \$175 million from approximately 70 defendants. The plume of contaminants has traveled under Kinder Morgan's Phoenix Terminal. The plaintiffs have advanced a novel theory that the releases of petroleum from the Phoenix Terminal (which are exempt under the petroleum exclusion under CERCLA) have facilitated the natural degradation of certain hazardous substances and thereby have resulted in a release of hazardous substances regulated under CERCLA. We are part of a joint defense group consisting of other terminal operators at the Phoenix Terminal including Chevron, BP, Salt River Project, Shell and a number of others, collectively referred to as the terminal defendants. Together, we filed a motion to dismiss all claims based on the petroleum exclusion under CERCLA. This case was assigned to a new judge, who has deemed all previous motions withdrawn and will grant leave to re-file such motions at a later date. We plan to re-file the motion to dismiss as well as numerous summary judgment motions as the judge allows.

Casper and Douglas, U.S. EPA Notice of Violation

In March 2011, the U.S. EPA conducted inspections of several environmental programs at the Douglas and Casper Gas Plants in Wyoming. In June 2011, we received two letters from the U.S. EPA alleging violations at both gas plants of the Risk Management Program requirements under the Clean Air Act. In September 2012, we entered into Combined Complaint and Consent Agreements and paid a monetary penalty of \$158,000 for each plant to resolve these issues.

The City of Los Angeles v. Kinder Morgan Liquids Terminals, LLC, Shell Oil Company, Equilon Enterprises LLC; California Superior Court, County of Los Angeles, Case No. NC041463

KMLT is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed beginning in 2009 and remains stayed through the next case management conference in March 2013. During the stay, the parties deemed responsible by the local regulatory agency (including the City of Los Angeles) have worked with that agency concerning the scope of the required cleanup and have now completed a sampling and testing program at the site. We anticipate that cleanup activities at the site will begin in the Spring of 2013. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including KMLT, have appealed those cleanup goals to the state water board. The state water board has not yet taken any action with regard to our appeal petitions.

Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed \$10 million, and that the plaintiff's past damages exceed \$2 million. No trial date has yet been set. We have begun settlement negotiations with the Port of Los Angeles.

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, LLC and ST Services, Inc.

On April 23, 2003, ExxonMobil filed a complaint in the Superior Court of New Jersey, Gloucester County. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September

2000, and later owned by Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, and it too is a party to the lawsuit.

On June 25, 2007, the NJDEP, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil and KMLT, formerly known as GATX Terminals Corporation, alleging natural resource damages related to historic contamination at the Paulsboro terminal. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals/Plains seeking to bring Support Terminals/Plains into the case. Support Terminals/Plains filed motions to dismiss the third party complaints, which were denied. Support Terminals/Plains is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases. All private parties and the state participated in two mediation conferences in 2010.

In mid 2011, KMLT and Plains Products entered into an agreement in principle with the NJDEP for settlement of the state's alleged natural resource damages claim. The parties then entered into a Consent Judgment which was subject to public notice and comment and court approval. The natural resource damage settlement includes a monetary award of \$1 million and a series of remediation and restoration activities at the terminal site. KMLT and Plains Products have joint responsibility for this settlement. Simultaneously, KMLT and Plains Products entered into a settlement agreement that settled each parties' relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now entered with the Court and the settlement is final. Now Plains will begin conducting remediation activities at the site and KMLT will provide oversight and 50% of the costs. The settlement with the state does not resolve the original complaint brought by ExxonMobil. KMLT and Plains received a settlement demand from ExxonMobil in the amount of \$1.38 million for past costs related to the remediation at the Paulsboro facility. Plains and KMLT are in discussions regarding the ExxonMobil offer. There is no trial date set.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. The City disclosed in discovery that it is seeking approximately \$170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased their claim for damages to approximately \$365 million.

The Court issued a Case Management Order on January 6, 2011, setting dates for completion of discovery and setting a trial date. In April 2011, the parties filed a joint stipulation to extend the discovery schedule by approximately three months. In December 2011, the parties again entered into a joint stipulation to extend the various schedules in the Court's Case Management Order. According to the schedule, the parties completed fact discovery in March 2012 and expert discovery in May 2012. Both parties filed their respective summary adjudication motions and motions to exclude experts on June 29, 2012. Oral arguments related to these motions are set for November 30, 2012. The trial is now set for April 9, 2013. We have been and will continue to aggressively defend this action. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. We continue to conduct an extensive remediation effort at the City's stadium property site.

Kinder Morgan, U.S. EPA Section 114 Information Request

On January 8, 2010, KMI, on behalf of Natural Gas Pipeline Company of America LLC, Horizon Pipeline Company and Rockies Express, received a Clean Air Act Section 114 information request from the U.S. EPA, Region V. This information request requires that the three affiliated companies provide the U.S. EPA with air permit and various other information related to their natural gas pipeline compressor station operations located in Illinois, Indiana, and Ohio. The affiliated companies have responded to the request and believe the relevant natural gas compressor station operations are in substantial compliance with applicable air quality laws and regulations.

Administrative Agreement with the U.S. EPA

In April 2011, we received Notices of Proposed Debarment from the U.S. EPA SDD. The Notices proposed the debarment of us (along with four of our subsidiaries), KMI, Kinder Morgan G.P., Inc., and Kinder Morgan Management, LLC, from participation in future federal contracting and assistance activities. The Notices alleged that certain of the respondents' past environmental violations indicated a lack of present responsibility warranting debarment.

In May 2012, we reached an administrative agreement with the U.S. EPA which resolved this matter without the debarment of any Kinder Morgan entities. The agreement requires independent monitoring of our Environmental Compliance and Ethics Programs, independent auditing of our facilities, enhanced training and notification requirements, and certain enhancements to our operational and compliance policies and procedures. We take environmental compliance very seriously and expect to comply with all aspects of this agreement.

TGP, PHMSA Notice of Violation

On April 25, 2012, the PHMSA issued an NOPV against TGP proposing \$118,500 in penalties for alleged violations discovered during an inspection prior to Kinder Morgan's ownership of TGP. We responded to the NOPV and paid the penalty to resolve this matter.

Other Environmental

We 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 law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide 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. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or cash flows.

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 cleanup.

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, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

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 will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of September 30, 2012, we have accrued an environmental reserve of \$110 million (including \$1 million of environmental related liabilities belonging to our FTC Natural Gas Pipelines disposal group). In addition, as of September 30, 2012, we have recorded a receivable of \$5 million for expected cost recoveries that have been deemed probable. As of December 31, 2011, our environmental reserve totaled \$75 million and our estimated receivable for environmental cost recoveries totaled \$5

million. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

11. Regulatory Matters

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. The amount of regulatory assets and liabilities reflected within “Deferred charges and other assets” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheets as of September 30, 2012 and December 31, 2011 are not material to our consolidated balance sheets. For information on our pipeline regulatory proceedings, see Note 10 “Litigation, Environmental and Other Contingencies—Federal Energy Regulatory Commission Proceedings” and “California Public Utilities Commission Proceedings.”

TGP's Proposed Sale of Production Area Facilities

On July 26, 2012, TGP filed an application with the FERC seeking authority to abandon by sale certain offshore and onshore supply facilities as well as a related offer of settlement that addresses the proposed rate and accounting treatment associated with the sale. The offer of settlement provides for a rate adjustment to TGP's maximum tariff rates upon the transfer of the assets and the establishment of a regulatory asset for a portion of the unrecovered net book value of the facilities to be sold. The sale is conditioned on approval by the FERC of both the requested abandonment authorization and offer of settlement. As of September 30, 2012, these assets totaled \$32 million and are included within "Assets held for sale" in our accompanying consolidated balance sheet. Additionally, we have recorded an approximately \$115 million regulated asset, which is included within "Deferred charges and other assets" in our accompanying consolidated balance sheet as of September 30, 2012, for the portion of the loss that we expect to recover through TGP's jurisdictional transportation rates as outlined in the FERC filing.

TGP Northeast Supply Diversification Project (Docket No. CP11-30-000)

On September 10, 2011, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in northern Pennsylvania and western New York along with an associated lease of transportation capacity from Dominion Transmission, Inc. in order to provide incremental firm transportation service to shippers of 250,000 dekatherms per day of natural gas produced in the Marcellus Shale supply area to northeast markets. The estimated capital cost of the project is \$56 million and the capacity is fully subscribed under long-term contracts. The project is planned to be placed in service on November 1, 2012.

TGP Northeast Upgrade Project (Docket No. CP11-161-000)

On May 29, 2012, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in Pennsylvania and New Jersey that will provide needed infrastructure to support continued development of Marcellus shale natural gas production and increase TGP's delivery capacity in the region by 636,000 dekatherms per day. The estimated capital cost of the project is approximately \$376 million and the capacity is fully subscribed under long term contracts. The project is anticipated to be placed in service on November 1, 2013.

TGP MPP Project (Docket No. CP12-28-000)

On August 9, 2012, the FERC issued an order authorizing the expansion of TGP's pipeline facilities in northwestern Pennsylvania that will provide needed infrastructure to support continued development of Marcellus shale natural gas production and increase TGP's delivery capacity in the region by 240,000 dekatherms per day. The estimated capital cost of the project is approximately \$89 million, and the capacity is fully subscribed under long term contracts. The project is anticipated to be placed in service on November 1, 2013.

TGP Rose Lake Expansion Project (Docket No. CP13-03-000)

On October 10, 2012, TGP filed an application with the FERC requesting authority to expand its pipeline capacity in northern Pennsylvania through the installation and modification of new and existing compression facilities that will result in increased capacity of 230,000 dekatherms per day and will improve the efficiency and reduce emissions by replacing certain older existing compression facilities. The project will further support continued development of Marcellus shale natural gas production in the region. The estimated capital cost of the project is approximately \$92 million and the capacity is fully subscribed under long term contracts. The project is anticipated to be placed in service on November 1, 2014.

EPNG Regulatory Matters

Docket No. RP08-426

In April 2010, the FERC approved an offer of settlement which increased EPNG's base tariff rates, effective January 1, 2009. The settlement resolved all but four issues in the proceeding. In January 2011, the presiding administrative law judge issued a decision that for the most part found against EPNG on those four issues. In May 2012, the FERC upheld the initial decision of the presiding administrative law judge in Opinion No. 517 on three of the issues and found in favor of EPNG on one of the issues. EPNG, along with other parties, has sought rehearing of those decisions to the FERC and may also seek review of any of the FERC's decisions to the U.S. Court of Appeals. However, in compliance with Opinion No. 517, EPNG filed with the FERC to implement certain aspects of the May 2012 order as they relate to rates under Docket No. RP08-426. Although the final outcome of all issues related to this open docket is not currently determinable, EPNG believes the accruals established for this matter are adequate.

Docket No. RP10-1398

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in base tariff rates which would increase revenues by approximately \$100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Hearings were conducted during the fourth quarter of 2011 and in June 2012, the presiding administrative law judge issued an initial decision which was overall favorable for EPNG. The initial decision is currently being reviewed by the FERC. Participants may appeal this decision to the FERC and ultimately seek review of the FERC's decision to the U.S. Court of Appeals. Additionally, certain customers have requested that the FERC require EPNG to decrease its currently effective recourse rates based on an order issued in May 2012 for matters in Docket No. RP08-426. The FERC issued an order requiring the implementation of its decisions in Docket No. RP08-426, which included interim reductions to the currently effective rates. Although EPNG requested rehearing on the interim rate decrease, EPNG filed proforma tariff records to comply with the FERC's order and requested adequate surcharge authority in the event the final rates are above the interim rates. That rehearing request and filing currently are pending before the FERC. EPNG is pursuing settlement with its customers of all issues in both open rate cases. It is uncertain whether the expected increase in revenues will be achieved in the context of any such settlement or following the final determination of the FERC or the courts on the rate matters. Although the final outcome is not currently determinable, EPNG believes the accruals established for this matter are adequate.

Docket No. CP12-6-000

On October 7, 2011, EPNG submitted an application, pursuant to Section 7(c) of the Natural Gas Act (NGA), requesting a certificate of public convenience and necessity authorizing the construction and operation of the Willcox Lateral 2013 Expansion Project located in Cochise County, Arizona. Concurrent with that application, EPNG also filed an application, pursuant to Section 3 of the NGA, for amended presidential permits to increase the export capacity of certain border crossings connected to the Willcox Lateral. At a cost of approximately \$23 million, the project consists of modifications to the existing EPNG Willcox Compressor Station, increasing the maximum allowable operating pressure of the Willcox Lateral, replacing various pipeline road crossings, and upgrading existing meter stations. The new project facilities would create 185,000 dekatherms per day of incremental capacity on the Willcox Lateral. A FERC order approving this project was issued on October 12, 2012, with construction activities beginning shortly thereafter to permit a project in-service date by the second quarter 2013.

12. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates (ASU) that we adopted and that became effective January 1, 2012 (including ASU No. 2011-8, “Intangibles—Goodwill and Other (Topic 350): Testing Goodwill for Impairment”) had a material impact on our consolidated financial statements.

ASU No. 2011-11

On December 16, 2011, the Financial Accounting Standards Board issued ASU No. 2011-11, “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.” This ASU requires disclosures to provide information to help reconcile differences in the offsetting requirements under U.S. Generally Accepted Accounting Principles and International Financial Reporting Standards. The disclosure requirements of this ASU mandate that entities disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an enforceable master netting arrangement or similar agreement. ASU No. 2011-11 also requires disclosure of collateral received and posted in connection with master netting arrangements or similar arrangements. The scope of this ASU includes derivative contracts, repurchase agreements, and securities borrowing and lending arrangements. Entities are required to apply the amendments of ASU No. 2011-11 for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. All disclosures provided by those amendments are required to be provided retrospectively for all comparative periods presented. We are currently reviewing the effects of ASU No. 2011-11.

ASU No. 2012-02

On July 27, 2012, the Financial Accounting Standards Board issued ASU No. 2012-02, “Intangibles-Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment.” This ASU allows an entity the option to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not (that is, a likelihood of more than 50%) that an indefinite-lived intangible asset other than goodwill is impaired. If, after this assessment, an entity concludes that it is not more likely than not that the indefinite-lived intangible asset is impaired, the entity is not required to take further action. However, if an entity concludes otherwise, then it is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test prescribed by current accounting principles. Moreover, an entity can bypass the qualitative assessment for any indefinite-lived intangible asset in any period and proceed directly to the quantitative impairment test, and then resume performing the qualitative assessment in any subsequent period. ASU No. 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 (January 1, 2013 for us), and early adoption is permitted. We are currently reviewing the effects of ASU No. 2012-02.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

General and Basis of Presentation

The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); (ii) our consolidated financial statements and related notes included in our 2011 Form 10-K; and (iii) our management’s discussion and analysis of financial condition and results of operations included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

We prepared our consolidated financial statements in accordance with U.S. generally accepted accounting principles. In addition, as discussed in Notes 1, 2, and 3 to our consolidated financial statements included elsewhere in this report, our financial statements reflect:

- the reclassifications necessary to reflect the results of our FTC Natural Gas Pipelines disposal group as discontinued operations. Accordingly, we have excluded the disposal group’s financial results from our Natural Gas Pipelines business segment disclosures for all periods presented in this report; and
- our August 1, 2012 acquisition of net assets from KMI as if such acquisition had taken place on May 25, 2012, the effective date that KMI acquired the same net assets from El Paso Corporation. We refer to this transfer of net

assets from KMI to us as the drop-down transaction, and we refer to the transferred assets as our drop-down asset group. We accounted for the drop-down transaction as a transfer of net assets between entities under common control, and accordingly, the financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations include the financial results of the drop-down asset group for all periods subsequent to May 25, 2012.

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 U.S. generally accepted accounting principles 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.

Furthermore, with regard to goodwill impairment testing, we review our goodwill for impairment annually, and we evaluated our goodwill for impairment on May 31, 2012. Our goodwill impairment analysis performed on that date did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units (including its inherent goodwill) is less than the carrying value of its net assets.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2011 Form 10-K and our Current Report on Form 8-K filed May 1, 2012.

Results of Operations

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

Consolidated

	Three Months Ended September 30,			
	2012	2011	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	\$ 150	\$ 103	\$ 47	46%
Natural Gas Pipelines(c).....	405	18	387	2,150%
CO ₂ (d).....	327	295	32	11%
Terminals(e).....	183	180	3	2%
Kinder Morgan Canada	56	48	8	17%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,121	644	477	74%
Depreciation, depletion and amortization expense(f)	(292)	(247)	(45)	(18)%
Amortization of excess cost of equity investments.....	(1)	(2)	1	50%
General and administrative expense(g).....	(131)	(100)	(31)	(31)%
Interest expense, net of unallocable interest income(h)	(181)	(132)	(49)	(37)%
Unallocable income tax expense	(2)	(2)	—	—%
Income from continuing operations	514	161	353	219%
Income (Loss) from discontinued operations(i)	(131)	55	(186)	(338)%
Net Income.....	383	216	167	77%
Net Income attributable to noncontrolling interests(j)	(4)	(1)	(3)	(300)%
Net Income attributable to Kinder Morgan Energy Partners, L.P.	\$ 379	\$ 215	\$ 164	76%

	Nine Months Ended September 30,			
	2012	2011	Earnings increase / (decrease)	
	(In millions, except percentages)			
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(k)	\$ 492	\$ 304	\$ 188	62%
Natural Gas Pipelines(l)	877	319	558	175%
CO ₂ (m).....	988	823	165	20%
Terminals(n)	565	525	40	8%
Kinder Morgan Canada(o)	158	150	8	5%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	3,080	2,121	959	45%
Depreciation, depletion and amortization expense(p)	(796)	(685)	(111)	(16)%
Amortization of excess cost of equity investments.....	(5)	(5)	—	—%
General and administrative expense(q).....	(379)	(387)	8	2%
Interest expense, net of unallocable interest income(r)	(474)	(393)	(81)	(21)%
Unallocable income tax expense	(7)	(7)	—	—%
Income from continuing operations	1,419	644	775	120%
Income (Loss) from discontinued operations(s)	(682)	145	(827)	(570)%
Net Income.....	737	789	(52)	(7)%
Net Income attributable to noncontrolling interests(t)	(12)	(6)	(6)	(100)%
Net Income (Loss) attributable to Kinder Morgan Energy Partners, L.P.	\$ 725	\$ 783	\$ (58)	(7)%

- (a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
- (b) 2012 amount includes a \$34 million increase in expense associated with environmental liability adjustments, a \$9 million increase in expense associated with rate case liability adjustments, and an \$8 million gain from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land, located in San Pedro, California. 2011 amount includes a \$69 million increase in expense associated with rate case, leased rights-of-way and other legal liability adjustments, and a \$6 million increase in expense associated with environmental liability adjustments.
- (c) 2012 amount includes (i) earnings of \$71 million attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; (ii) a \$1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a \$1 million decrease in income from incremental severance expenses. 2011 amount includes a \$167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value.
- (d) 2012 and 2011 amounts include a \$5 million decrease in income and an \$8 million increase in income, respectively, from unrealized gains and losses on derivative contracts used to hedge forecast crude oil sales.
- (e) 2012 amount includes a \$1 million increase in expense related to hurricane clean-up and repair activities. 2011 amount includes (i) a \$1 million increase in expense associated with storm damage and repair activities at our Carteret, New Jersey liquids terminal; (ii) a \$1 million loss from property write-offs associated with the on-going dissolution of our partnership interest in Globalplex Handling; and (iii) a \$1 million gain from the sale of our ownership interest in Arrow Terminals B.V.
- (f) 2012 amount includes a \$14 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012.
- (g) 2012 amount includes (i) a \$13 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; (ii) a \$3 million increase in unallocated severance expenses; and (iii) a \$2 million increase in expense for certain asset and business acquisition costs. 2011 amount includes (i) a \$1 million decrease in unallocated payroll tax expense (related to an \$87 million special bonus expense to non-senior management employees allocated to us from KMI in the first quarter of 2011); however, we do not have any obligation, nor did we pay any amounts related to this compensation expense; and (ii) a \$1 million increase in expense for certain asset and business acquisition costs.

- (h) 2012 amount includes an \$8 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012, and a \$1 million increase in expense attributable to incremental fees related to our short-term bridge loan credit facility.
- (i) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount consists of a \$131 million loss before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (including a combined \$178 million loss from both costs to sell and the remeasurement of net assets to fair value). 2011 amount consists of \$62 million of earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments, and \$7 million of depreciation and amortization expense.
- (j) 2012 and 2011 amounts include decreases of \$1 million and \$3 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the three month 2012 and 2011 items previously disclosed in these footnotes.
- (k) 2012 amount includes a \$34 million increase in expense associated with environmental liability adjustments, a \$9 million increase in expense associated with rate case liability adjustments, and an \$8 million gain from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land. 2011 amount includes (i) a \$234 million increase in expense associated with rate case, leased rights-of-way, and other legal liability adjustments; (ii) a \$6 million increase in expense associated with environmental liability adjustments; and (iii) an \$11 million gain from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land.
- (l) 2012 amount includes (i) earnings of \$131 million attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; (ii) a \$1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a \$1 million decrease in income from incremental severance expenses. 2011 amount includes a \$167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value.
- (m) 2012 and 2011 amounts include an \$8 million decrease in income and a \$10 million increase in income, respectively, from unrealized gains and losses on derivative contracts used to hedge forecast crude oil sales. 2012 amount also includes a \$7 million gain from the sale of our ownership interest in the Claytonville oil field unit.
- (n) 2012 amount includes a \$12 million casualty indemnification gain related to a 2010 casualty at our Port Sulphur, Louisiana, International Marine Terminal facility, and a \$1 million increase in expense related to hurricane clean-up and repair activities. 2011 amount includes (i) a \$5 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense); (ii) a \$4 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (iii) a combined \$2 million increase in income from adjustments associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009; (iv) a combined \$2 million increase in income associated with the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.; (v) a \$1 million gain from the sale of our ownership interest in Arrow Terminals B.V.; (vi) a \$4 million increase in expense at our Carteret terminal, associated with storm and fire damage and repair activities, environmental liability adjustments, and the settlement of a certain litigation matter; (vii) a \$1 million loss from property write-offs associated with the on-going dissolution of our partnership interest in Globalplex Handling; and (viii) a \$1 million loss from property write-offs associated with the 2010 casualty at our International Marine Terminal facility.
- (o) 2011 amount includes a \$2 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense).
- (p) 2012 amount includes a \$31 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012.
- (q) 2012 amount includes (i) a \$56 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; (ii) a \$4 million increase in unallocated severance expenses; and (iii) a \$2 million increase in expense for certain asset and business acquisition costs. 2011 amount includes (i) a combined \$90 million increase in non-cash compensation expense (including \$87 million related to a special bonus expense to non-senior management employees) allocated to us from KMI in the first quarter of 2011; however, we do not have any obligation, nor did we pay any amounts related to this compensation expense; (ii) a \$2 million increase in expense for certain asset and business acquisition costs; and (iii) a \$1 million increase in unallocated payroll tax expense (related to an \$87 million special bonus expense to non-senior management employees allocated to us from KMI in the first quarter of 2011); however, we do not have any obligation, nor did we pay any amounts related to this compensation expense.
- (r) 2012 amount includes a \$21 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012, and a \$1 million increase in expense attributable to incremental fees related to our short-term bridge loan credit facility.
- (s) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount consists of (i) a \$675 million loss before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (including a combined \$827 million loss from both costs to sell and the remeasurement of net assets to fair value); and (ii) \$7 million of depreciation and amortization expense. 2011 amount consists of (i) \$165 million of earnings before depreciation, depletion and

amortization expense and amortization of excess cost of equity investments (including a \$10 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011); and (ii) \$20 million of depreciation and amortization expense.

- (t) 2012 and 2011 amounts include decreases of \$4 million and \$7 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the nine month 2012 and 2011 items previously disclosed in these footnotes.

As more fully described in our 2011 Form 10-K and our Current Report on Form 8-K filed May 1, 2012, we own and manage a diversified portfolio of energy transportation and storage assets, and primarily, our business model is designed to generate stable, fee-based income that provides overall long-term value to our unitholders. Our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves). Distributable cash flow, sometimes referred to as DCF, is an overall performance metric we use as a measure of available cash, and the calculation of our DCF, for each of the three and nine month periods ended September 30, 2012 and 2011 is as follows (calculated before the combined effect from all of the three and nine month certain items disclosed in the footnotes to the tables above):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Net Income	\$ 383	\$ 216	\$ 737	\$ 789
Add-back: Certain items - combined expense(a)	191	235	838	479
Net Income before certain items	574	451	1,575	1,268
Less: Net Income before certain items attributable to noncontrolling interests	(5)	(4)	(16)	(13)
Net Income before certain items attributable to Kinder Morgan Energy Partners, L.P.	569	447	1,559	1,255
Less: General Partner's interest in Net Income before certain items(b) ..	(367)	(301)	(1,025)	(876)
Limited Partners' interest in Net Income before certain items	202	146	534	379
Depreciation, depletion and amortization(c)	331	292	913	834
Book (cash) taxes paid, net	—	9	7	19
Incremental contributions from equity investments in the Express Pipeline and Endeavor Gathering LLC	—	2	3	8
Sustaining capital expenditures(d)	(78)	(55)	(174)	(140)
Distributable cash flow (DCF) before certain items	\$ 455	\$ 394	\$ 1,283	\$ 1,100

- (a) Equal to the combined effect from all of the three and nine month 2012 and 2011 items previously disclosed in the footnotes to the tables included above.
- (b) Three and nine month 2012 amounts include decreases in income of \$6 million and \$19 million, respectively, and three and nine month 2011 amounts include decreases in income of \$7 million and \$21 million, respectively, for waived incentive amounts related to common units issued to finance a portion of our May 2010 KinderHawk Field Services LLC acquisition.
- (c) Three and nine month 2012 amounts include increases in expense of \$52 million and \$136 million, respectively, and three and nine month 2011 amounts include increases in expense of \$36 million and \$124 million, respectively, for our proportionate share of the depreciation expenses of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) Fayetteville Express Pipeline LLC; (iv) Cypress Interstate Pipeline LLC; (v) EagleHawk Field Services LLC; (vi) Red Cedar Gathering LLC; (vii) for 2012 amounts only, Eagle Ford Gathering LLC, El Paso Midstream Investment Company LLC, El Paso Natural Gas Pipeline LLC and Bear Creek Storage LLC; and (viii) for 2011 amounts only, KinderHawk Field Services LLC.
- (d) Three and nine month 2012 amounts include increases in expenditures of \$8 million and \$13 million, respectively, and nine month 2011 amount includes an increase in expenditures of \$3 million, all for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) Fayetteville Express Pipeline LLC; (iv) Cypress Interstate Pipeline LLC; (v) EagleHawk Field Services LLC; (vi) Eagle Ford Gathering LLC; (vii) Red Cedar Gathering LLC; (viii) El Paso Natural Gas Pipeline LLC; (ix) Bear Creek Storage LLC; and (x) El Paso Midstream Investment Company, LLC.

With regard to our reportable business segments, we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

For the comparable third quarter periods of 2012 and 2011, our total segment earnings before depreciation, depletion and amortization expenses increased \$477 million (74%) in 2012; however, this overall increase in earnings:

- included a \$263 million increase in earnings before depreciation, depletion and amortization expenses from the effect of the certain items described in footnotes (b), (c), (d), and (e) to the table above (which combined to increase total segment EBDA by \$28 million in the third quarter of 2012 and decrease segment EBDA by \$235 million in the third quarter of 2011); and
- excluded a \$15 million decrease in earnings before depreciation, depletion and amortization expenses from discontinued operations (as described in footnote (i) to the table above and excluding the combined \$178 million loss from both costs to sell and the remeasurement of net assets to fair value in the third quarter of 2012).

After adjusting for these two items, the remaining \$199 million (21%) increase in quarterly segment earnings before depreciation, depletion and amortization resulted primarily from better performance in the third quarter of 2012 from all five of our business segments.

For the comparable nine month periods, total segment earnings before depreciation, depletion and amortization expenses increased \$959 million (45%) in 2012; however, this overall increase:

- included a \$480 million increase in earnings before depreciation, depletion and amortization expenses from the effect of the certain items described in footnotes (k), (l), (m), (n) and (o) to the table above (which combined to increase total segment EBDA by \$104 million in the first nine months of 2012 and decrease segment EBDA by \$376 million in the first nine months of 2011); and
- excluded a \$23 million decrease in earnings before depreciation, depletion and amortization expenses from discontinued operations (as described in footnote (s) to the table above and excluding both the combined \$827 million loss from costs to sell and the remeasurement of net assets to fair value in the first nine months of 2012 and the \$10 million increase in expense in the third quarter of 2011 from the write-off of a receivable for fuel under-collected prior to 2011).

After adjusting for these two items, the remaining \$456 million (17%) increase in segment earnings before depreciation, depletion and amortization in the first nine months of 2012 versus the first nine months of 2011 resulted from higher earnings from our Natural Gas Pipelines, CO₂, and Terminals, and Kinder Morgan Canada business segments, partially offset by lower earnings from our Products Pipelines business segment.

Products Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(In millions, except operating statistics)				
Revenues	\$ 386	\$ 242	\$ 940	\$ 695
Operating expenses(a)	(256)	(146)	(497)	(426)
Other income (expense)(b)	7	(1)	7	10
Earnings from equity investments.....	14	12	43	35
Interest income and Other, net.....	1	1	11	4
Income tax (expense) benefit	(2)	(5)	(12)	(14)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 150	\$ 103	\$ 492	\$ 304
Gasoline (MMBbl)(c)	98.1	101.7	292.9	297.2
Diesel fuel (MMBbl).....	36.3	37.2	105.7	110.7
Jet fuel (MMBbl).....	28.3	28.1	84.0	82.9
Total refined product volumes (MMBbl)	162.7	167.0	482.6	490.8
Natural gas liquids (MMBbl)	8.5	7.6	23.1	19.8
Total delivery volumes (MMBbl)(d)	171.2	174.6	505.7	510.6
Ethanol (MMBbl)(e)	8.9	8.0	24.1	23.0

- (a) Three and nine month 2012 amounts include a \$34 million increase in expense associated with environmental liability adjustments, and a \$9 million increase in expense associated with rate case liability adjustments. Three and nine month 2011 amounts include increases in expense of \$69 million and \$234 million, respectively, associated with rate case, leased rights-of-way and other legal liability adjustments, and a \$6 million increase in expense associated with environmental liability adjustments.
- (b) Three and nine month 2012 amounts include a gain of \$8 million, and nine month 2011 amount includes a gain of \$11 million, all from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land.
- (c) Volumes include ethanol pipeline volumes.
- (d) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.
- (e) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Combined, the certain items described in footnotes (a) and (b) to the table above accounted for increases in segment earnings before depreciation, depletion and amortization expenses of \$40 million in the third quarter of 2012, and \$194 million in the the first nine months of 2012, when compared to the same two periods of 2011. Following is information, for each of the comparable three and nine month periods of 2012 and 2011, related to the segment's (i) remaining \$7 million (4%) increase and \$6 million (1%) decrease in earnings before depreciation, depletion and amortization; and (ii) \$144 million increase (60%) and \$245 million (35%) increase in operating revenues:

Three months ended September 30, 2012 versus Three months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Transmix operations.....	\$ 3	34%	\$ 152	1,344%
Cochin Pipeline.....	2	15%	(5)	(18)%
Southeast Terminals	2	11%	—	—%
Calnev Pipeline.....	(2)	(15)%	(2)	(10)%
Pacific operations.....	(1)	(2)%	(5)	(4)%
All others (including eliminations)	3	7%	4	9%
Total Products Pipelines	\$ 7	4%	\$ 144	60%

Nine months ended September 30, 2012 versus Nine months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations.....	\$ (17)	(7)%	\$ (15)	(5)%
Transmix operations.....	(11)	(44)%	259	713%
Calnev Pipeline.....	(6)	(14)%	(4)	(7)%
Cochin Pipeline.....	12	30%	(3)	(5)%
Plantation Pipeline	3	8%	1	6%
All others (including eliminations)	13	8%	7	4%
Total Products Pipelines	\$ (6)	(1)%	\$ 245	35%

The primary increases and decreases in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the comparable three and nine month periods of 2012 and 2011 included the following:

- an increase of \$3 million (34%) and a decrease of \$11 million (44%), respectively, from our transmix processing operations. The quarter-to-quarter increase in earnings was driven by favorable pricing. The drop in earnings across the comparable nine month periods was primarily due to a decrease in processing volumes and unfavorable net carrying value adjustments to product inventory. The period-to-period increases in revenues were due mainly to the expiration of certain transmix fee-based processing agreements in March 2012. Due to the expiration of these contracts, we now directly purchase incremental volumes of transmix and sell incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;
- increases of \$2 million (15%) and \$12 million (30%), respectively, from our Cochin Pipeline—the increase in earnings in the comparable quarterly periods was primarily due to a favorable income tax adjustment. The increase in earnings across the comparable year-to-date periods was largely due to a 25% increase in pipeline throughput volumes (due in part to completed expansion projects since the end of the third quarter of 2012), and to the favorable settlement of a pipeline access dispute;
- decreases of \$2 million (15%) and \$6 million (14%), respectively, from our Calnev Pipeline—chiefly due to lower period-to-period delivery volumes that were due in part to incremental services offered by a competing pipeline;
- for the comparable three month periods, a \$2 million (11%) increase from our Southeast terminal operations—due mainly to increased throughput volumes of refined products and biofuels;
- decreases of \$1 million (2%) and \$17 million (7%), respectively, from our Pacific operations. Earnings were essentially flat across both quarterly periods, but decreased in the comparable nine month periods due primarily to lower operating revenues. Mainline transportation revenues dropped in the first nine months of 2012, due largely

to lower average FERC tariffs as a result of rate case rulings settlements made since the end of the third quarter of 2011; and

- for the comparable nine month periods, an increase of \$3 million (8%) from our approximate 51% interest in the Plantation pipeline system—due largely to higher transportation revenues driven by higher average tariff rates since the end of the third quarter of 2011.

Natural Gas Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions, except operating statistics)			
Revenues(a)	\$ 1,113	\$ 1,093	\$ 2,699	\$ 2,999
Operating expenses(b)	(783)	(939)	(1,966)	(2,608)
Other expense	(1)	—	(1)	—
Earnings from equity investments(c)	75	29	145	95
Interest income and Other, net(d)	2	(165)	3	(164)
Income tax (expense) benefit	(1)	—	(3)	(3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments from continuing operations	405	18	877	319
Discontinued operations(e)	(131)	62	(675)	165
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments including discontinued operations	\$ 274	\$ 80	\$ 202	\$ 484
Natural gas transport volumes (Bcf)(f)	1,772.1	1,598.1	5,175.8	4,708.9
Natural gas sales volumes (Bcf)(f)	228.7	215.1	657.2	598.7

- (a) Three and nine month 2012 amounts include increases of \$82 million and \$181 million, respectively, attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012.
- (b) Three and nine month 2012 amounts include (i) increases of \$19 million and \$51 million, respectively, attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; and (ii) a \$1 million increase in expense related to hurricane clean-up and repair activities.
- (c) Three and nine month 2012 amounts include a \$1 million decrease in earnings from incremental severance expenses. Three month 2012 amount also includes an increase of \$7 million attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012.
- (d) Three and nine month 2012 amounts include an increase of \$1 million attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012. Three and nine month 2011 amounts include a \$167 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value.
- (e) Represents earnings (losses) before depreciation, depletion and amortization expense attributable to our FTC Natural Gas Pipelines disposal group. Three and nine month 2012 amounts include losses of \$178 million and \$827 million, respectively, from both incremental selling expenses and the remeasurement of net assets to fair value. Nine month 2011 amount includes a \$10 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. Three and nine month 2012 amounts also include revenues of \$71 million and \$204 million, respectively, and three and nine month 2011 amounts also include revenues of \$83 million and \$241 million, respectively.
- (f) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC, Fayetteville Express Pipeline LLC, Rockies Express Pipeline LLC, Tennessee Gas Pipeline L.L.C., El Paso Natural Gas Pipeline LLC and Texas intrastate natural gas pipeline group pipeline volumes. Volumes for acquired pipelines are included for all periods.

Combined, the certain items described in footnotes (a) through (e) to the table above increased our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization (including discontinued operations) by \$58 million in the third quarter of 2012, and decreased earnings before depreciation, depletion and amortization by

\$521 million in the first nine months of 2012, when compared to the same prior year periods. The certain items also accounted for increases of \$82 million and \$181 million, respectively, in segment revenues for both comparable three and nine month periods. Following is information, for each of the comparable three and nine month periods of 2012 and 2011 and including discontinued operations, related to the increases and decreases in the segment's (i) remaining \$136 million (55%) and \$239 million (36%) increases in earnings before depreciation, depletion and amortization; and (ii) remaining \$74 million (6%) and \$518 million (16%) decreases in operating revenues:

Three months ended September 30, 2012 versus Three months ended September 30, 2011

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
(In millions, except percentages)				
Tennessee Gas Pipeline	\$ 124	n/a	\$ 166	n/a
El Paso Natural Gas Pipeline(b).....	15	n/a	n/a	n/a
Kinder Morgan Treating operations	13	119%	30	191%
Eagle Ford Gathering(b)	9	529%	n/a	n/a
Fayetteville Express Pipeline(b).....	7	118%	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	(12)	(17)%	(252)	(25)%
KinderHawk Field Services(a).....	(3)	(7)%	(1)	(2)%
All others (including eliminations).....	<u>(2)</u>	<u>(4)%</u>	<u>(5)</u>	<u>(15)%</u>
Total Natural Gas Pipelines-continuing operations	151	82%	(62)	(6)%
Discontinued operations(c).....	<u>(15)</u>	<u>(24)%</u>	<u>(12)</u>	<u>(14)%</u>
Total Natural Gas Pipelines-including discontinued operations....	\$ 136	55%	\$ (74)	(6)%

Nine months ended September 30, 2012 versus Nine months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
(In millions, except percentages)				
Tennessee Gas Pipeline	\$ 124	n/a	\$ 166	n/a
KinderHawk Field Services(a).....	63	93%	100	203%
Kinder Morgan Treating operations	31	95%	74	155%
Fayetteville Express Pipeline(b).....	28	239%	n/a	n/a
Eagle Ford Gathering(b)	15	919%	n/a	n/a
El Paso Natural Gas Pipeline(b).....	15	n/a	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	(19)	(8)%	(816)	(29)%
All others (including eliminations).....	<u>5</u>	4%	<u>(5)</u>	(5)%
Total Natural Gas Pipelines-continuing operations	262	54%	(481)	(16)%
Discontinued operations(c).....	<u>(23)</u>	(13)%	<u>(37)</u>	(15)%
Total Natural Gas Pipelines-including discontinued operations....	\$ 239	36%	\$ (518)	(16)%

n/a – not applicable

- (a) Equity investment until July 1, 2011. See Note (b).
(b) Equity investment. We record earnings under the equity method of accounting, but we receive distributions in amounts essentially equal to equity earnings plus depreciation and amortization expenses less sustaining capital expenditures.
(c) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

The overall increases in our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the comparable three and nine month periods of 2012 and 2011 were driven by incremental contributions from (i) our Tennessee Gas Pipeline and our 50%-owned El Paso Natural Gas Pipeline, which we acquired

from KMI effective August 1, 2012; and (ii) the inclusion of a full nine months of operations in 2012 from our Kinder Morgan Treating operations, which we acquired from SouthTex Treaters, Inc. effective November 30, 2011.

Other significant increases and decreases in our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization in the comparable three and nine month periods of 2012 and 2011 included the following:

- incremental equity earnings of \$9 million and \$15 million, respectively, from our 50%-owned Eagle Ford Gathering LLC, which initiated flow on its natural gas gathering system on August 1, 2011;
- increases of \$7 million (118%) and \$28 million (239%), respectively, attributable to incremental equity earnings from our 50%-owned Fayetteville Express pipeline system—driven by a ramp-up in firm contract transportation volumes, and to lower interest expense. Period-to-period transportation revenues increased due to increases in natural gas transmission volumes of 8% and 15%, respectively, and the decreases in interest expense related to Fayetteville's refinancing of its prior bank credit facility in July 2011;
- decreases of \$12 million (17%) and \$19 million (8%), respectively, from our Texas intrastate natural gas pipeline group. The decreases were driven by higher operating and maintenance expenses, lower margins on natural gas processing activities, and for the comparable nine month periods, by lower margins on natural gas sales. The increases in expenses were driven by both higher pipeline integrity maintenance and unexpected well repairs. The decreases in processing margins were mostly due to lower natural gas liquids prices, and the period-to-period decrease in sales margin was primarily due to lower average natural gas sales prices;
- a decrease of \$3 million (7%) and an increase of \$63 million (93%), respectively, from our now wholly-owned KinderHawk Field Services LLC. The quarter-to-quarter decrease in earnings related primarily to lower gathering volumes and lower cashout settlement revenues. The increase across the comparable nine month periods was mainly due to incremental earnings resulting from the inclusion of a full nine months of operations in 2012. Effective July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk that we did not already own.

The period-to-period decreases in earnings before depreciation, depletion and amortization from discontinued operations were largely due to lower operating revenues from both our Kinder Morgan Interstate Gas Transmission and Trailblazer pipeline systems. The decreases generally related to lower net fuel recoveries, lower margins on operational natural gas sales, and excess natural gas transportation capacity existing out of the Rocky Mountain region.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three and nine month periods of 2012 and 2011 primarily relate to the natural gas purchase and sale activities of our Texas intrastate natural gas pipeline group, with the variances from period-to-period in both revenues and operating expenses mainly due to corresponding changes in the intrastate group's average prices and volumes for natural gas purchased and sold. Our intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its gas sales revenues are largely offset by corresponding increases and decreases in its gas purchase costs. For the comparable third quarter periods of 2012 and 2011, our Texas intrastate natural gas pipeline group accounted for 68% and 85%, respectively, of the segment's revenues, and 85% and 94%, respectively, of the segment's operating expenses. For the comparable nine month periods of both years, the intrastate group accounted for 73% and 87%, respectively, of total segment revenues, and 87% and 94%, respectively, of total segment operating expenses.

CO₂

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(In millions, except operating statistics)				
Revenues(a)	\$ 420	\$ 372	\$ 1,250	\$ 1,063
Operating expenses	(97)	(83)	(282)	(256)
Other income(b)	—	—	7	—
Earnings from equity investments	5	7	18	18
Interest income and Other, net	1	1	—	2
Income tax (expense) benefit	(2)	(2)	(5)	(4)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 327	\$ 295	\$ 988	\$ 823
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(c)	1.2	1.2	1.2	1.2
Southwest Colorado carbon dioxide production (net) (Bcf/d)(c)	0.5	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	30.0	29.4	28.4	28.9
SACROC oil production (net)(MBbl/d)(e)	25.0	24.5	23.7	24.1
Yates oil production (gross)(MBbl/d)(d)	20.6	21.5	20.9	21.7
Yates oil production (net)(MBbl/d)(e)	9.3	9.5	9.3	9.6
Katz oil production (gross)(MBbl/d)(d)	1.8	0.5	1.7	0.3
Katz oil production (net)(MBbl/d)(e)	1.5	0.4	1.4	0.3
Natural gas liquids sales volumes (net)(MBbl/d)(e)	9.3	8.4	9.3	8.4
Realized weighted average oil price per Bbl(f)	\$ 88.64	\$ 70.43	\$ 88.39	\$ 69.54
Realized weighted average natural gas liquids price per Bbl(g)	\$ 44.27	\$ 68.86	\$ 51.53	\$ 65.53

- (a) Three and nine month 2012 amounts include unrealized losses of \$5 million and \$8 million, respectively, and three and nine month 2011 amounts include unrealized gains of \$8 million and \$10 million, respectively, all relating to derivative contracts used to hedge forecast crude oil sales.
- (b) Nine month 2012 amount represents the gain from the sale of our ownership interest in the Claytonville oil field unit.
- (c) Includes McElmo Dome and Doe Canyon sales volumes.
- (d) 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, and an approximately 99% working interest in the Katz Strawn unit.
- (e) Net to us, after royalties and outside working interests.
- (f) Includes all of our crude oil production properties.
- (g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO₂ segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO₂) and crude oil, and the production and marketing of natural gas and natural gas liquids. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and its Sales and Transportation Activities.

For the three and nine months ended September 30, 2012, the certain items described in footnotes (a) and (b) to the table above (i) decreased earnings before depreciation, depletion and amortization by \$13 million and \$11 million, respectively; and (ii) decreased revenues by \$13 million and \$18 million, respectively, when compared to the same two periods of 2011. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three and nine month periods of 2012 and 2011, in the segment's remaining (i) \$45 million (16%) and \$176 million (22%) increases in earnings before depreciation, depletion and amortization; and (ii) \$61 million (17%) and \$205 million (19%) increases in operating revenues:

Three months ended September 30, 2012 versus Three months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
(In millions, except percentages)				
Oil and Gas Producing Activities	\$ 32	15%	\$ 51	18%
Sales and Transportation Activities	13	19%	8	9%
Intrasegment eliminations	—	—%	2	9%
Total CO ₂	\$ 45	16%	\$ 61	17%

Nine months ended September 30, 2012 versus Nine months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
(In millions, except percentages)				
Oil and Gas Producing Activities	\$ 137	23%	\$ 169	20%
Sales and Transportation Activities	39	17%	30	11%
Intrasegment eliminations	—	—%	6	11%
Total CO ₂	\$ 176	22%	\$ 205	19%

The increases in earnings for the comparable three and nine month periods of 2012 and 2011 from the segment's oil and gas producing activities were driven by increases of \$68 million (30%) and \$188 million (29%), respectively, in crude oil sales revenues. The increases were due to both higher average realizations for U.S. crude oil, increased oil production at the Katz field unit, and for the comparable nine month periods, to increased oil production at the SACROC field unit. When compared to the same periods a year ago, our realized weighted average price per barrel of crude oil increased 26% in the third quarter of 2012 (from \$70.43 per barrel in third quarter 2011 to \$88.64 per barrel in third quarter 2012) and 27% in the first nine months of 2012 (from \$69.54 per barrel in the first nine months of 2011 to \$88.39 per barrel in the first nine months of 2012). Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged \$89.07 and \$92.23 per barrel in the third quarter and first nine months of 2012, respectively, and \$87.73 and \$92.71 per barrel in the third quarter and first nine months of 2011, respectively. Partially offsetting the increases in crude oil sales revenues were decreases in plant product sales revenues of \$15 million (29%) and \$19 million (12%), respectively, due to period-to-period decreases in the realized weighted average price per barrel of natural gas liquids of 36% and 21%, respectively.

The increases in earnings before depreciation, depletion and amortization expenses from the segment's sales and transportation activities were driven by higher non-consent revenues, higher reimbursable project revenues, and for the comparable nine month periods, higher carbon dioxide sales revenues. The increases in non-consent revenues related to sharing arrangements pertaining to certain expansion projects completed at the McElmo Dome unit in Colorado since the end of the third quarter of 2011. The increase in reimbursable revenues related to the completion of prior expansion projects on the Central Basin pipeline system. Although essentially flat across both comparable quarterly periods, the revenues we realized from carbon dioxide sales increased by \$15 million (8%) in the first nine months of 2012, when compared to the first nine months of last year. The increase was driven by a 17% increase in average sales prices, due primarily to two factors: (i) a change in the mix of contracts resulting in more carbon dioxide being delivered under higher price contracts; and (ii) heavier weighting of new carbon dioxide contract prices to the price of crude oil.

Terminals

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(In millions, except operating statistics)				
Revenues	\$ 334	\$ 328	\$ 1,018	\$ 980
Operating expenses(a)	(156)	(156)	(480)	(480)
Other income(b)	2	2	15	5
Earnings from equity investments.....	5	3	16	8
Interest income and Other, net(c).....	—	—	1	5
Income tax (expense) benefit(d)	(2)	3	(5)	7
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments.....	\$ 183	\$ 180	\$ 565	\$ 525
Bulk transload tonnage (MMtons)(e)	23.7	26.7	74.2	74.8
Ethanol (MMBbl)	15.7	15.5	49.9	44.9
Liquids leaseable capacity (MMBbl)	60.2	59.5	60.2	59.5
Liquids utilization %	92.9%	93.2%	92.9%	93.2%

- (a) Three and nine month 2012 amounts include increases in expense of \$1 million related to hurricane clean-up and repair activities. Three and nine month 2011 amounts include increases in expense of \$1 million and \$4 million, respectively, at our Carteret, New Jersey liquids terminal, associated with storm and fire damage and repair activities, environmental liability adjustments, and the settlement of a certain litigation matter. Nine month 2011 amount also includes a \$1 million increase in expense associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009.
- (b) Nine month 2012 amount includes a \$12 million casualty indemnification gain related to a 2010 casualty at our Port Sulphur, Louisiana, International Marine Terminal facility. Three and nine month 2011 amounts include a \$1 million loss from property write-offs associated with the on-going dissolution of our partnership interest in Globalplex Handling, and a \$1 million gain from the sale of our ownership interest in Arrow Terminals B.V. Nine month 2011 amount also includes (i) a \$4 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) a \$1 million gain associated with the sale of our ownership interest in the boat fleet business described in footnote (a); and (iii) a \$1 million loss from property write-offs associated with the 2010 casualty at our International Marine Terminal facility.
- (c) Nine month 2011 amount includes a \$4 million gain associated with the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.
- (d) Nine month 2011 amount includes (i) a \$5 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense); (ii) a \$2 million decrease in expense (reflecting tax savings) related to the net decrease in income from the sale of our ownership interest in the boat fleet business described in footnote (a); and (iii) a \$2 million increase in expense associated with the increase in income from the sale of a 51% ownership interest in two of our subsidiaries described in footnote (c).
- (e) Volumes for acquired terminals are included for all periods and include our proportionate share of joint venture tonnage.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. For the nine months ended September 30, 2012, the certain items related to our Terminals business segment and described in the footnotes to the table above increased earnings before depreciation, depletion and amortization by \$3 million, when compared to the first nine months of 2011.

Following is information related to the increases and decreases, in the comparable three and nine month periods of 2012 and 2011, in the segment's (i) \$3 million (2%) and remaining \$37 million (7%) increases in earnings before depreciation, depletion and amortization; and (ii) \$6 million (2%) and \$38 million (4%) increases in operating revenues:

Three months ended September 30, 2012 versus Three months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	\$ 5	12%	\$ 4	7%
Mid-Atlantic	4	32%	5	14%
Acquired assets and businesses	2	n/a	—	n/a
Northeast.....	1	7%	4	14%
Gulf Bulk	(3)	(15)%	—	—%
Rivers	(1)	(9)%	(6)	(13)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(5)	(6)%	(1)	(1)%
Total Terminals	\$ 3	2%	\$ 6	2%

Nine months ended September 30, 2012 versus Nine months ended September 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic.....	\$ 17	39%	\$ 21	23%
Gulf Liquids	15	12%	14	8%
Northeast.....	8	14%	14	14%
Acquired assets and businesses	8	n/a	4	n/a
Gulf Bulk	3	6%	3	2%
Rivers	(7)	(14)%	(11)	(9)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(7)	(3)%	(7)	(2)%
Total Terminals	\$ 37	7%	\$ 38	4%

The overall increases in earnings before depreciation, depletion and amortization from our Terminals segment were driven by higher contributions from both our Gulf Liquids and Mid-Atlantic regions. The increases from our Gulf Liquids facilities were driven by higher warehousing revenues (as a result of new and renewed customer agreements at higher rates), higher ethanol volumes through our Deer Park, Texas rail terminal, and for the comparable nine month periods, by higher overall gasoline throughput volumes. For all liquids facilities combined, we increased our liquids leasable capacity by 0.7 million barrels (1.2%) since the end of the third quarter of last year, primarily via completed terminal expansion projects, and, at the same time, our overall liquids utilization capacity rate remained essentially flat across both comparable three and nine month periods.

The period-to-period earnings increases from our Mid-Atlantic region across both comparable three and nine month periods resulted primarily from higher export coal shipments from our Pier IX terminal, located in Newport News, Virginia, and higher import steel and iron ore imports from our Fairless Hills, Pennsylvania bulk terminal. Economic expansion in developing countries has generated a growth cycle in the coal export market, and for all terminals combined, our total export coal volumes increased by 1.2 million tons (32%) in the third quarter of 2012 and by 4.9 million tons (45%) in the first nine months of 2012, when compared to the same prior year periods.

The incremental earnings and revenues from acquired assets and businesses primarily represent contributions from our additional equity investment in the short-line railroad operations of Watco Companies, LLC (acquired in December 2011) and our bulk terminal that handles petroleum coke for the Total refinery in Port Arthur, Texas (acquired in June 2011). The incremental amounts represent earnings and revenues from acquired terminals' operations during the additional

months of ownership in the first nine months of 2012, and do not include increases or decreases during the same months we owned the assets in 2011.

Earnings before depreciation, depletion and amortization from our Gulf Bulk terminals decreased in the third quarter of 2012 compared to the third quarter of 2011, due mainly to favorable cost of sales expense adjustments and to the favorable settlement of a petroleum coke rate escalation issue, both recognized in the third quarter of 2011. Earnings increased across the comparable nine month periods, due primarily to higher coal and petroleum coke handling and loading operations at our Deepwater and Port of Houston terminal facilities located on the Houston Ship Channel.

Combined earnings from all of the terminal operations included in our Rivers region was essentially unchanged across both three month periods, but decreased \$7 million (14%) in the comparable year-to-date periods. The decrease was driven by lower coal transload volumes in the first nine months of 2012, largely the result of a drop in domestic demand.

Kinder Morgan Canada

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
(In millions, except operating statistics)				
Revenues	\$ 80	\$ 77	\$ 226	\$ 230
Operating expenses	(28)	(27)	(75)	(77)
Earnings (loss) from equity investments	1	1	3	(1)
Interest income and Other, net	5	3	12	10
Income tax (expense) benefit(a)	(2)	(6)	(8)	(12)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 56	\$ 48	\$ 158	\$ 150
Transport volumes (MMBbl)(b)	28.1	25.6	79.9	75.2

(a) Nine month 2011 amount includes a \$2 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense).

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and our one-third ownership interest in the Express crude oil pipeline system. The certain item relating to income tax savings described in footnote (a) to the table above decreased segment earnings before depreciation, depletion and amortization by \$2 million in the first nine months of 2012, when compared to the same period last year. For each of the segment's three primary businesses, following is information for each of the comparable three and nine month periods of 2012 and 2011, related to the segment's (i) \$8 million (17%) and remaining \$10 million (7%) increases in earnings before depreciation, depletion and amortization; and (ii) \$3 million (4%) increase and and \$4 million (2%) decrease in operating revenues:

Three months ended September 30, 2012 versus Three months ended September 30, 2011

	EBDA increase/(decrease))		Revenues increase/(decrease))	
	(In millions, except percentages)			
Trans Mountain Pipeline	\$ 6	13%	\$ 3	4%
Express Pipeline(a).....	2	53%	n/a	n/a
Jet Fuel Pipeline.....	—	—%	—	—%
Total Kinder Morgan Canada ...	\$ 8	17%	\$ 3	4%

Nine months ended September 30, 2012 versus Nine months ended September 30, 2011

	EBDA increase/(decrease))		Revenues increase/(decrease))	
	(In millions, except percentages))			
Trans Mountain Pipeline	\$ 5	4%	\$ (4)	(2)%
Express Pipeline(a).....	5	58%	n/a	n/a
Jet Fuel Pipeline.....	—	—%	—	—%
Total Kinder Morgan Canada ...	\$ 10	7%	\$ (4)	(2)%

(a) Equity investment. We record earnings under the equity method of accounting.

The period-to-period increases in Trans Mountain's earnings before depreciation, depletion and amortization expenses were mainly due to lower income tax expenses, and partly due to higher non-operating income related to incremental management incentive fees earned from its operation of the Express pipeline system. The drop in income tax expenses related primarily to favorable tax adjustments taken in the third quarter of 2012 related to lower taxable income. The period-to-period increases in earnings from our equity investment in the Express pipeline system were mainly due to volumes moving at higher transportation rates on the Express portion of the system, and higher domestic volumes on the Platte portion of the segment.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
General and administrative expenses(a)	<u>\$ 131</u>	<u>\$ 100</u>	<u>\$ 379</u>	<u>\$ 387</u>
Interest expense, net of unallocable interest income(b) ..	<u>\$ 181</u>	<u>\$ 132</u>	<u>\$ 474</u>	<u>\$ 393</u>
Unallocable income tax expense	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 7</u>	<u>\$ 7</u>
Net income attributable to noncontrolling interests(c) ...	<u>\$ 4</u>	<u>\$ 1</u>	<u>\$ 12</u>	<u>\$ 6</u>

(a) Three and nine month 2012 amounts include (i) increases in expense of \$13 million and \$56 million, respectively, attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; (ii) increases in unallocated severance expenses of \$3 million and \$4 million, respectively; and (iii) increases in expense of \$2 million for certain asset and business acquisition costs. Three and nine month 2011 amounts include (i) a \$1 million decrease in unallocated payroll tax expense and a \$1 million increase in unallocated payroll tax expense, respectively (all related to an \$87 million special bonus expense to non-senior management employees allocated to us from KMI in the first quarter of 2011); however, we do not have any obligation, nor did we pay any amounts related to this compensation expense; and (ii) increases in expense of \$1 million and \$2 million,

respectively, for certain asset and business acquisition costs. Nine month 2011 amount also includes a combined \$90 million increase in non-cash compensation expense (including \$87 million related to the special bonus expense to non-senior management employees) allocated to us from KMI in the first quarter of 2011); however, we do not have any obligation, nor did we pay any amounts related to this expense.

- (b) Three and nine month 2012 amounts include (i) increases in expense of \$8 million and \$21 million, respectively, attributable to our drop-down asset group for periods prior to our acquisition date of August 1, 2012; and (ii) increases in expense of \$1 million attributable to incremental fees related to our short-term bridge loan credit facility.
- (c) Three and nine month 2012 amounts include decreases of \$1 million and \$4 million, respectively, in net income attributable to our noncontrolling interests, and the three and nine month 2011 amounts include decreases of \$3 million and \$7 million, respectively, in net income attributable to our noncontrolling interests, all related to the combined effect of the three and nine month 2012 and 2011 items previously disclosed in the footnotes to the tables included above in “—Results of Operations.”

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as unallocated salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services. These expenses are generally not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. For this reason and because we manage our business based on our reportable business segments and not on the basis of our ownership structure, we do not specifically allocate our general and administrative expenses to our business segments. As discussed previously, we use segment earnings before depreciation, depletion and amortization (EBDA) internally as a measure of profit and loss used for evaluating segment performance, and each of our segment's EBDA includes all costs directly incurred by that segment.

For the three and nine months ended September 30, 2012, the certain items described in footnote (a) to the table above accounted for an \$18 million increase and a \$31 million decrease, respectively, in our general and administrative expenses, when compared to the same periods a year ago. The remaining \$13 million (13%) and \$23 million (8%) period-to-period increases in expenses were driven by the acquisition of additional business, associated primarily with the Tennessee Gas and El Paso Natural Gas (50% interest) pipeline systems we acquired from KMI effective August 1, 2012. We also realized higher benefit and payroll tax expenses, and higher employee labor expenses, which were impacted by cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force.

We report our interest expense as “net,” meaning that we have subtracted unallocated interest income and capitalized interest from our interest expense to arrive at one interest amount, and after taking into effect the certain items described in footnote (b) to the table above, our net interest expense increased \$40 million (30%) in the third quarter of 2012 and \$59 million (15%) in the first nine months of 2012, when compared with the same prior year periods. The increases in interest expense were primarily due to higher average debt balances in 2012. Average borrowings for the three and nine month periods ended September 30, 2012 increased 30% and 28%, respectively, when compared to the same periods a year ago, largely due to the capital expenditures, business acquisitions (including debt assumed from the drop-down transaction), and joint venture contributions we have made since the end of the third quarter of 2011. The weighted average interest rate on all of our borrowings—including both short-term and long-term amounts—increased 4% in the comparable quarterly periods (from 4.12% for the third quarter of 2011 to 4.28% for the third quarter of 2012), but was essentially unchanged across both nine month periods (from 4.28% for the first nine months of 2011 to 4.26% for the first nine months of 2012).

We use interest rate swap agreements to transform 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 September 30, 2012 and December 31, 2011, approximately 46% and 47%, respectively, of our consolidated debt balances (excluding our debt fair value adjustments) was 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 6 “Risk Management—Interest Rate Risk Management” to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of September 30, 2012, we had \$532 million of “Cash and cash equivalents” on our consolidated balance sheet (included elsewhere in this report), an increase of \$123 million (30%) from December 31, 2011. We also had, as of September 30, 2012, approximately \$1.0 billion of borrowing capacity available under our two unsecured credit facilities (discussed below in “—Short-term Liquidity”). We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash (which may result from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings (including commercial paper issuances), and the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;
- interest payments with cash flows from operating activities; and
- debt principal payments, as such debt principal payments become due, with additional borrowings or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in “—Financing Activities.”

Credit Ratings and Capital Market Liquidity

Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (stable) and BBB (stable), at Standard & Poor’s Ratings Services, Moody’s Investors Service, Inc. and Fitch, Inc., respectively. Our short-term corporate debt credit rating is A-2 (susceptible to adverse economic conditions, however, capacity to meet financial commitments is satisfactory), Prime-2 (strong ability to repay short-term debt obligations) and F2 (good quality grade with satisfactory capacity to meet financial commitments), at Standard & Poor’s Ratings Services, Moody’s Investors Service, Inc. and Fitch, Inc., respectively. Our credit ratings affect our ability to access the commercial paper market and the public and private debt markets, as well as the terms and pricing of our debt (see Part II, Item 1A “Risk Factors”). Based on these credit ratings, we expect that our short-term liquidity needs will be met primarily through borrowings under our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy pipeline and terminals industries and other financial and business factors, some of which are beyond our control.

Short-term Liquidity

As of September 30, 2012, our principal sources of short-term liquidity were (i) our \$2.2 billion senior unsecured revolving credit facility with a diverse syndicate of banks that matures July 1, 2016; (ii) our \$2.0 billion short-term bridge loan credit facility that matures February 6, 2013, and which, as of September 30, 2012, allowed for maximum borrowings of \$1.7 billion; (iii) our \$3.9 billion short-term commercial paper program (which is supported by our two credit facilities, with the amount available for borrowing under our credit facilities being reduced by our outstanding commercial paper borrowings and letters of credit); and (iv) cash from operations (discussed below in “—Operating Activities”). The loan commitments under our two credit facilities can be used to fund borrowings for general partnership purposes and as a backup for our commercial paper program, and our \$2.2 billion long-term senior unsecured revolving

credit facility can be amended to allow for borrowings of up to \$2.5 billion. As of September 30, 2012, we had no outstanding borrowings under either credit facility. For more information about our \$2.0 billion short-term credit agreement, which we entered into effective August 6, 2012, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report.

Our outstanding short-term debt as of September 30, 2012 was \$2,697 million, primarily consisting of \$2,664 million of outstanding commercial paper borrowings. We intend to refinance our current short-term debt through the proceeds we expect to receive from the sale of our FTC Natural Gas Pipelines disposal group, and a combination of long-term debt, equity, and/or the issuance of additional commercial paper or credit facility borrowings to replace maturing commercial paper and current maturities of long-term debt. As of December 31, 2011, our short-term debt totaled \$1,638 million.

We had a working capital deficit of \$794 million as of September 30, 2012, and a working capital deficit of \$1,543 million as of December 31, 2011. The overall \$749 million (49%) favorable change from year-end 2011 was primarily due to (i) an increase in working capital due to reclassifying the September 30, 2012 net assets of our FTC Natural Gas Pipelines disposal group as current assets and liabilities held for sale (we expect to sell the disposal group's net assets in the fourth quarter of 2012 and because the disposal group's combined liabilities were not material to our consolidated balance sheet, we included the disposal group's liabilities within "Accrued other current liabilities" in our accompanying consolidated balance sheet as of September 30, 2012, included elsewhere in this report); and (ii) a decrease in working capital due to an increase in short-term debt. 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 cash and cash equivalent balances as a result of debt or equity issuances (discussed below in "—Long-term Financing").

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions of cash from operations to our common unitholders, Class B unitholder and general partner) through issuing long-term debt securities or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

Our equity offerings consist of the issuance of additional common units or the issuance of additional i-units to KMR (which KMR purchases with the proceeds from the sale of additional KMR shares). As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors. For more information about our equity issuances in the first nine months of 2012, see Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. Our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate senior notes provide that we may redeem the notes 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.

In addition, from time to time our subsidiary Tennessee Gas Pipeline L.L.C. has issued long-term debt securities, often referred to as its senior notes. As of September 30, 2012, Tennessee Gas Pipeline L.L.C. is the obligor of six separate series of fixed-rate unsecured senior notes having a combined principal amount of \$1,790 million. The interest rates on these notes range from 7% per annum through 8.375% per annum, and the maturity dates range from February 2016 through April 2037. We assumed these senior notes as part of the drop-down transaction.

As of September 30, 2012 and December 31, 2011, the aggregate principal amount of the various series of our senior notes was \$13,350 million and \$12,050 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries (including Tennessee Gas Pipeline L.L.C.'s senior notes discussed above) was \$1,900 million and \$126 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt related

transactions in the first nine months of 2012, see Note 4 “Debt” to our consolidated financial statements included elsewhere in this report. For additional information regarding our debt securities, see Note 8 “Debt” to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term senior notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See “—Credit Ratings and Capital Market Liquidity” above for a discussion of our credit ratings.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset. For the first nine month periods of 2012 and 2011, our sustaining capital expenditures totaled \$174 million and \$140 million, respectively. These amounts included \$13 million and \$3 million, respectively, for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) Fayetteville Express Pipeline LLC; (iv) Cypress Interstate Pipeline LLC; (v) EagleHawk Field Services LLC; (vi) Eagle Ford Gathering LLC; (vii) Red Cedar Gathering Company; (viii) for the periods after our acquisition date of August 1, 2012 only, El Paso Natural Gas Pipeline LLC, Bear Creek Storage Company, L.L.C., and El Paso Midstream Investment Company, LLC; and (ix) for the first six months of 2011 only, KinderHawk Field Services LLC (effective July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk that we did not already own and we subsequently included its sustaining capital expenditures in our consolidated totals).

In addition, we have forecasted \$306 million for sustaining capital expenditures for the full year 2012. This amount (i) includes expenditures associated with the drop-down asset group we acquired from KMI since May 25, 2012 (discussed above in “—General and Basis of Presentation”); and (ii) excludes expenditures associated with the assets in our FTC Natural Gas Pipelines disposal group for the months after the expected disposal.

Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Rockies Express, Midcontinent Express and Fayetteville Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, with proceeds from issuing their own long-term notes, or with proceeds from contributions received from their member owners. We have no contingent debt obligations with respect to Rockies Express, Midcontinent Express, or Fayetteville Express.

In addition to the sustaining capital expenditures described above (excluding the proportionate share of the sustaining capital expenditures of our unconsolidated joint ventures), our consolidated statements of cash flows for the nine months ended September 30, 2012 and 2011 include capital expenditures of \$1,112 million and \$701 million, respectively. We report our combined capital expenditures separately as “Capital expenditures” within the “Cash Flows from Investing Activities” section on our accompanying cash flow statements (included elsewhere in this report), and the period-to-period increase in our capital expenditures was primarily due to higher investment undertaken in the first nine months of 2012 to expand and improve our Terminals and Natural Gas Pipelines business segments. Generally, we initially fund our capital expenditures through borrowings under our commercial paper program or our revolving credit facilities until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

Capital Requirements for Recent Drop-Down Transaction

In the first nine months of 2012, our cash outlays for the drop-down transaction totaled \$3,482 million (net of an acquired cash balance of \$3 million) and we reported this amount separately as “Payment to KMI for drop-down asset group” on our accompanying consolidated statement of cash flows included elsewhere in this report. With the exception of our partial payment of the combined purchase price to KMI by the issuance of addition common units (valued at \$381 million), we funded this acquisition with proceeds received from (i) our August 2012 issuance of long-term senior notes; (ii) our third quarter 2012 issuances of additional i-units to KMR; (iii) borrowings under our short-term bridge loan credit facility; and (iv) borrowings under our commercial paper program. We subsequently repaid the borrowings made under

our short-term bridge loan credit facility with incremental borrowings under our commercial paper program, and as of September 30, 2012, we had no borrowings under the credit facility.

Additional Capital Requirements

In April 2012, we announced that we will proceed with our proposal to expand our existing Trans Mountain pipeline system. When completed, the proposed expansion will increase capacity on Trans Mountain from its current 300,000 barrels per day of crude oil and refined petroleum products to approximately 750,000 barrels per day. This expansion project entails the following: (i) twinning the existing pipeline within the existing right-of-way, where possible; (ii) adding new pump stations along the route; (iii) increasing the number of storage tanks at existing facilities; and (iv) expanding the Westridge Marine terminal, located within Port Metro Vancouver in Vancouver, British Columbia. We confirmed binding commercial support for this project, and pending the filing and approval of tolling and facilities applications with Canada's National Energy Board, we expect to begin construction in 2015 or 2016, with the proposed project operating in late 2017. Our current estimate of total construction costs on the project is approximately \$4.1 billion.

In addition, we regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. Such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations. Excluding amounts for the drop-down asset group we acquired from KMI and the expansion projects associated with those assets, we now expect to invest approximately \$2.2 billion for our 2012 capital expansion program, including small acquisitions and investment contributions.

Our ability to make accretive acquisitions (i) is a function of the availability of suitable acquisition candidates at the right cost; (ii) is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions; and (iii) includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates. Our ability to expand our assets is also impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such expansions.

As a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required.

Operating Activities

Net cash provided by operating activities was \$2,314 million for the nine months ended September 30, 2012, versus \$1,984 million for the same comparable period of 2011. The period-to-period increase of \$330 million (17%) in cash flow from operations was primarily due to a \$311 million increase in cash from overall higher partnership income—after adjusting our period-to-period \$52 million decrease in net income for the following six non-cash items:

- a \$582 million increase from non-cash losses from the remeasurement of net assets to fair value (discussed further in Note 2 to our consolidated financial statements included elsewhere in this report);
- a \$98 million increase due to higher non-cash depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments);
- a \$78 million increase from a non-cash expense recognized in the third quarter of 2012 related to the divestiture of our FTC Natural Gas Pipelines disposal group. We expect to pay the liability associated with this expense in the fourth quarter of 2012 (as discussed in Note 9 “Related Party Transactions—FTC Natural Gas Pipelines Disposal Group Selling Expenses” to our consolidated financial statements included elsewhere in this report, KMI has agreed to contribute \$45 million to us as partial funding for this payment);
- a \$230 million decrease related to higher non-cash expenses in the first nine months of 2011 as a result of adjustments to our rate case, leased rights-of-ways and other legal liabilities;

- a \$90 million decrease due to certain higher non-cash compensation expenses allocated to us from KMI in the first nine months of 2011 (as discussed in Note 9 “Related Party Transactions—Non-Cash Compensation Expenses” to our consolidated financial statements included elsewhere in this report, we do not have any obligation, nor did we pay any amounts related to these allocated expenses); and
- a \$75 million decrease due to higher earnings from equity investees in the first nine months of 2012.

The period-to-period change in partnership income in 2012 versus 2011 is discussed above in “—Results of Operations” (including all of the certain items disclosed in the associated table footnotes).

Investing Activities

Net cash used in investing activities was \$4,786 million for the nine month period ended September 30, 2012, compared to \$1,797 million used in the comparable 2011 period (our issuance of an aggregate consideration of \$289 million in common units for the acquisition of a 50% ownership interest in El Paso Midstream Investment Company, LLC in June 2012 and our issuance of an aggregate consideration of \$381 million in common units as partial payment for the drop-down asset group in August 2012 is included within “Noncash Investing and Financing Activities—Assets acquired or liabilities settled by the issuance of common units” on our accompanying consolidated statement of cash flows included elsewhere in this report. The overall \$2,989 million (166%) decrease in cash from investing activities primarily consisted of the following:

- our \$3,482 million cash outlay (net of an acquired cash balance of \$3 million) as partial payment for the drop-down asset group in August 2012, as described above in “—Capital Requirements for Recent Drop-Down Transaction;”
- a \$435 million decrease in cash due to higher capital expenditures, as described above in “—Capital Expenditures;” and
- an \$873 million increase in cash due to lower expenditures for the acquisitions of assets and investments from unrelated parties. In the first nine months of 2012, we paid a combined \$72 million for asset acquisitions, including (i) \$30 million to Enhanced Oil Resources to acquire a carbon dioxide source field and related assets located in Apache County, Arizona, and Catron County, New Mexico; and (ii) \$28 million to Lincoln Oil Co. Inc. to acquire an ethanol and biodiesel terminaling facility located in Belton, South Carolina. In the first nine months of 2011, we spent an aggregate amount of \$945 million for asset and investment acquisitions, including (i) \$835 million for both our remaining 50% ownership interest in KinderHawk Field Services LLC and our 25% equity interest in EagleHawk Field Services LLC; (ii) \$50 million for an initial preferred equity interest in Watco Companies, LLC; and (iii) \$43 million for a newly constructed petroleum coke terminal located in Port Arthur, Texas.

Financing Activities

Net cash provided by financing activities amounted to \$2,582 million for the first nine months of 2012. In the comparable prior year period, we used \$30 million in cash from financing activities. The \$2,612 million (871%) overall increase in cash from the comparable 2011 period was mainly due to the following:

- a \$2,487 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. This increase in cash was primarily due to (i) a \$2,188 million increase due to higher short-term net borrowings under our commercial paper program (largely related to the portion of the drop-down transaction we funded in cash); (ii) a \$154 million increase due to the immediate repayment of all of the outstanding borrowings under KinderHawk Field Services LLC’s bank credit facility that we assumed on our July 1, 2011 acquisition date; and (iii) a combined \$144 million increase due to higher net issuances of our senior notes (in the first nine months of 2012 and 2011, we generated net proceeds of \$1,280 million and \$1,136 million, respectively, from both issuing and repaying senior notes);
- a \$301 million increase in cash due to higher partnership equity issuances. This increase reflects the \$1,114 million we received, after commissions and underwriting expenses, from the sales of additional common units and i-units in the first nine months of 2012 (discussed in Note 5 “Partners’ Capital—Equity Issuances” to our consolidated financial statements included elsewhere in this report), versus the \$813 million we received from the sales of additional common units in the first nine months a year ago; and

- a \$200 million decrease in cash due to higher partnership distributions. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our noncontrolling interests, totaled \$1,859 million in the first nine months of 2012. In the same comparable period last year, we distributed \$1,659 million to our partners. Further information regarding our distributions is discussed following in “—Partnership Distributions.”

Partnership Distributions

Our partnership agreement requires that we distribute 100% of “Available Cash,” as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. Our 2011 Form 10-K and our Current Report on Form 8-K filed May 1, 2012 contain additional information concerning our partnership distributions, including the definition of “Available Cash,” the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including our noncontrolling interests.

For further information about the partnership distributions we paid in the third quarters of 2012 and 2011 (for the second quarterly periods of 2012 and 2011, respectively), see Note 5 “Partners’ Capital—Income Allocation and Declared Distributions” to our consolidated financial statements included elsewhere in this report.

Furthermore, on October 17, 2012, we declared a cash distribution of \$1.26 per unit for the third quarter of 2012 (an annualized rate of \$5.04 per unit). This distribution is 9% higher than the \$1.16 per unit distribution we made for the third quarter of 2011. Our declared distribution for the third quarter of 2012 of \$1.26 per unit will result in an incentive distribution to our general partner of \$364 million (including the effect of a waived incentive distribution amount of \$6 million related to our KinderHawk acquisition). Comparatively, our distribution of \$1.16 per unit paid on November 14, 2011 for the third quarter of 2011 resulted in an incentive distribution payment to our general partner in the amount of \$299 million (and included the effect of a waived incentive distribution amount of \$7 million related to our KinderHawk acquisition). The increased incentive distribution to our general partner for the third quarter of 2012 over the incentive distribution for the third quarter of 2011 reflects the increase in the distribution per unit as well as the issuance of additional units. For additional information about our third quarter 2012 cash distribution, see Note 5 “Partners’ Capital—Subsequent Events” to our consolidated financial statements included elsewhere in this report. For additional information about our 2011 partnership distributions, see Notes 10 and 11 to our consolidated financial statements included in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

Currently, we expect to declare cash distributions of \$4.98 per unit for 2012, an 8% increase over our cash distributions of \$4.61 per unit for 2011. We also expect that the combination of the asset divestitures and the drop-down transaction with KMI (discussed in Note 1 and Note 2 to our consolidated financial statements included elsewhere in this report) will be slightly accretive to our distribution per unit in 2012 and nicely accretive thereafter.

Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO₂ business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids, and while we hedge the majority of our crude oil production, we do have exposure on our unhedged volumes, the majority of which are natural gas liquids volumes. Our 2012 budget assumes an average West Texas Intermediate (WTI) crude oil price of approximately \$93.75 per barrel (with some minor adjustments for timing, quality and location differences) in 2012, and based on the actual prices we have received through the date of this report and the forward price curve for WTI (adjusted for the same factors used in our 2012 budget), we currently expect the average price of WTI crude oil will be approximately \$95.25 per barrel in 2012. For 2012, we expect that every \$1 change in the average WTI crude oil price per barrel will impact our CO₂ segment’s cash flows by approximately \$6 million (or slightly over 0.1% of our combined business segments’ anticipated earnings before depreciation, depletion and amortization expenses). This sensitivity to the average WTI price is very similar to what we experienced in 2011.

Furthermore, we currently expect to be unfavorably impacted in 2012 by lower natural gas liquids prices, which we now project to be approximately 21% lower for the full year 2012 than was assumed when we developed our 2012 budget, which equates to a negative impact of over \$50 million. Due to the deteriorating natural gas liquid prices, we now expect to generate 2012 distributable cash flow slightly above our distributions, but below our budgeted amount.

Off Balance Sheet Arrangements

There have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2011 in our 2011 Form 10-K and in our Current Report on Form 8-K filed May 1, 2012.

Recent Accounting Pronouncements

Please refer to Note 12 “Recent Accounting Pronouncements” to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

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,” “position,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions 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 of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

See Part I, Item 1A “Risk Factors” and Part II, Item 7 “Management's Discussion and Analysis of Financial Condition and Results of Operations—Information Regarding Forward-Looking Statements” of our 2011 Form 10-K and Part II, Item 1A “Risk Factors” in this report for a more detailed description of factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in our 2011 Form 10-K and in this report. The risk 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, to update any forward-looking statements to reflect future events or developments after the date of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2011, in Item 7A of our 2011 Form 10-K and our Current Report on Form 8-K filed May 1, 2012. For more information on our risk management activities, see Note 6 “Risk Management” to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of September 30, 2012, 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. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 10 to our consolidated financial statements entitled “Litigation, Environmental and Other Contingencies,” which is incorporated in this item by reference.

Item 1A. Risk Factors.

Except as set forth below, there have been no material changes in or additions to the risk factors disclosed in Part I, Item 1A “Risk Factors” in our 2011 Form 10-K.

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 could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Also, continuing 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.

In addition, due to our relationship with KMI, our credit ratings, and thus our ability to access the capital markets and the terms and pricing we receive therein, may be adversely affected by any impairments to KMI's financial condition or adverse changes in its credit ratings. Similarly, any reduction in our credit ratings could negatively impact the credit ratings of our subsidiaries, which could increase their cost of capital and negatively affect their business and operating results. 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 debt instruments, as well as the market value of our common units.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

On August 13, 2012, we paid to KMI \$3,482 million in cash, issued 4,667,575 common units, and assumed \$2.3 billion in debt for the acquisition of certain natural gas pipeline assets. We valued the common units at \$381 million, determining the units' value based on the \$81.52 closing market price of the common units on the New York Stock Exchange on the August 13, 2012 issuance date. The units were issued to KMI pursuant to Section 4(2) of the Securities Act of 1933.

On August 6, 2012, we issued 114,429 common units as part of our purchase price for certain refined petroleum products terminal assets we acquired from Lincoln Oil Company. The total purchase price for the acquired assets was \$37 million, consisting of \$28 million in cash, and \$9 million in common units. We valued the common units at \$9 million, determining the units' value based on the \$80.43 closing market price of the common units on the New York Stock Exchange on the August 6, 2012 issuance date. The units were issued to a single accredited investor in a transaction not involving a public offering and were therefore exempt from registration pursuant to Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95 to this quarterly report.

Item 5. Other Information.

None.

Item 6. Exhibits.

- *2.1 — Purchase and Sale Agreement, dated as of August 17, 2012, between Kinder Morgan Operating L.P. "A" and Tallgrass Energy Partners, LP (filed as exhibit 2.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed August 23, 2012 and incorporated herein by reference).
- *2.2 — Purchase and Sale Agreement, dated as of August 17, 2012, between Kinder Morgan Operating L.P. "A" and Tallgrass Energy Partners, LP (filed as exhibit 2.2 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed August 23, 2012 and incorporated herein by reference).
- *2.3 — Contribution Agreement, dated as of August 6, 2012, among Kinder Morgan, Inc., El Paso TGPC Investments, L.L.C., El Paso EPNG Investments, L.L.C. and Kinder Morgan Energy Partners, L.P. (filed as exhibit 2.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed August 6, 2012 and incorporated herein by reference).
- 4.1 — Certificate of the Vice President 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 3.45% Senior Notes due February 15, 2023, and the 5.00% Senior Notes due August 15, 2042.
- 4.2 — Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K (17 CFR 229.601). Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
- *10.1 — Credit Agreement dated as of August 6, 2012 among Kinder Morgan Energy Partners, L.P.; Wells Fargo Bank, National Association, as Administrative Agent; Barclays Bank PLC, as Syndication Agent; and the lenders party thereto (filed as exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed August 10, 2012 and incorporated herein by reference).
- 11 — Statement re: computation of per share earnings.
- 12 — Statement re: computation of ratio of earnings to fixed charges.
- 31.1 — Certification by CEO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 — Certification by CFO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 — Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 — Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 95 — Mine Safety Disclosures.
- 101 — Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three and nine months ended September 30, 2012 and 2011; (ii) our Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2012 and 2011; (iii) our Consolidated Balance Sheets as of September 30, 2012 and December 31, 2011; (iv) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2012 and 2011; and (v) the notes to our Consolidated Financial Statements.

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

noted otherwise.

SIGNATURE

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 ENERGY PARTNERS, L.P.

Registrant (A Delaware limited partnership)

By: **KINDER MORGAN G.P., INC.,**

its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC,**

the Delegate of Kinder Morgan G.P., Inc.

Date: October 29, 2012

By: /s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)

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

Form 10-K

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

For the fiscal year ended December 31, 2011

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: 1-11234

Kinder Morgan Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware
*(State or other jurisdiction of
incorporation or organization)*

76-0380342
*(I.R.S. Employer
Identification No.)*

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

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

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Units	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 ☒ No ☐

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 ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

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. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2011 was approximately \$15,631,284,352. As of January 31, 2012, the registrant had 232,837,732 Common Units outstanding.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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PART I

Items 1 and 2. *Business and Properties.*

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to “we,” “us,” “our,” “KMP” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P., our operating limited partnerships and their majority-owned and controlled subsidiaries. We own an interest in or operate approximately 29,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described more fully below in “(c) Narrative Description of Business—Business Segments”).

Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals, and handle such products as ethanol, coal, petroleum coke and steel. We are also the leading provider of carbon dioxide, commonly called CO₂, for enhanced oil recovery projects in North America. As one of the largest publicly traded pipeline limited partnerships in America, we have an enterprise value of over \$40 billion. The address of our principal executive offices is 500 Dallas Street, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000.

You should read the following in conjunction with our audited consolidated financial statements and the notes thereto included elsewhere in this report. We have prepared our accompanying consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. Our accounting records are maintained in United States dollars, and all references to dollars in this report are United States dollars, except where stated otherwise. Canadian dollars are designated as C\$. Our consolidated financial statements include our accounts and those of our operating limited partnerships and their majority-owned and controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation.

(a) General Development of Business

Organizational Structure

We are a Delaware limited partnership formed in August 1992, and our common units, which represent limited partner interests in us, trade on the New York Stock Exchange under the symbol “KMP.” In general, our limited partner units, consisting of common units, Class B units (the Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange) and i-units, will vote together as a single class, with each common unit, Class B unit, and i-unit having one vote. Our partnership agreement requires us to distribute all of our available cash, as defined in our partnership agreement, to our partners on a quarterly basis within 45 days after the end of each calendar quarter. We pay our quarterly distributions to our common unitholders, our sole Class B unitholder and our general partner in cash, and we pay our quarterly distributions to our sole i-unitholder in additional i-units rather than in cash. For further information about our distributions, see Note 11 “Related Party Transactions—Partnership Interests and Distributions” to our consolidated financial statements included elsewhere in this report.

Our general partner is owned by Kinder Morgan, Inc., as discussed below. In July 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC.

Kinder Morgan, Inc., Kinder Morgan Kansas, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation and referred to as KMI in this report, indirectly owns all the common stock of Kinder Morgan Kansas, Inc. Kinder Morgan Kansas, Inc. is a Kansas corporation and indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation. KMI was formed August 23, 2006 as a Delaware limited liability company principally for the purpose of acquiring (through a wholly-owned subsidiary) all of the common stock of Kinder Morgan Kansas, Inc. The merger, referred to in this report as the going-private transaction, closed on May 30, 2007 with Kinder Morgan Kansas, Inc. continuing as the surviving legal entity.

On February 10, 2011, KMI converted from a Delaware limited liability company named Kinder Morgan Holdco LLC to a Delaware corporation named Kinder Morgan, Inc., and its outstanding units were converted into classes of capital stock. On February 16, 2011, KMI completed the initial public offering of its common stock. All of the common stock that was sold in the offering was sold by existing investors, consisting of funds advised by or affiliated with Goldman, Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC. No members of management sold

shares in the offering, and KMI did not receive any proceeds from the offering. KMI's common stock trades on the New York Stock Exchange under the symbol "KMI."

As of December 31, 2011, KMI and its consolidated subsidiaries owned, through KMI's general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 12.4% interest in us. In addition to the distributions it receives from its limited and general partner interests, KMI also receives an incentive distribution from us as a result of its ownership of our general partner. Including both its general and limited partner interests in us, at the 2011 distribution level, KMI received approximately 50% of all quarterly distributions of available cash from us, with approximately 44% and 6% of all quarterly distributions from us attributable to KMI's general partner and limited partner interests, respectively.

On October 16, 2011, KMI and El Paso Corporation announced a definitive agreement whereby KMI will acquire all of the outstanding shares of El Paso in a transaction that would, as of the announcement date, create an energy company that would have an enterprise value of approximately \$94 billion and would own an interest in approximately 80,000 miles of pipelines. As of the announcement date, the total purchase price, including the assumption of debt outstanding at both El Paso Corporation and El Paso Pipeline Partners, L.P., was approximately \$38 billion. El Paso Corporation owns a 42% limited partner interest and the 2% general partner interest in El Paso Pipeline Partners, L.P. The transaction is expected to close in the second quarter of 2012 and is subject to customary regulatory approvals.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company formed in February 2001. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. KMR's shares represent limited liability company interests and trade on the New York Stock Exchange under the symbol "KMR."

Under the delegation of control agreement, KMR, as the delegate of our general partner, manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their majority-owned and controlled subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their majority-owned and controlled subsidiaries. As of December 31, 2011, KMR, through its sole ownership of our i-units, owned approximately 29.3% of all of our outstanding limited partner units.

Recent Developments

The following is a brief listing of significant developments since December 31, 2010. We begin with developments pertaining to our reportable business segments. Additional information regarding most of these items may be found elsewhere in this report.

Products Pipelines

- In February 2011, our subsidiary SFPP, L.P. entered into a settlement agreement with a shipper regarding various interstate transportation rate challenges filed with the Federal Energy Regulatory Commission, referred to in this report as the FERC. In March 2011, we made payments of \$63.0 million pursuant to this settlement agreement. Additionally, in September 2011, we made refund payments to various intrastate transportation shippers totaling \$18.4 million. During 2011, we recognized a combined \$251.8 million increase in expense due to adjustments of our liabilities related to interstate and intrastate transportation rate challenges and certain other litigation matters involving our West Coast Products Pipeline operations;

- On May 5, 2011, we announced an approximately \$220 million investment to build a new crude oil/condensate pipeline that will initially transport 50,000 barrels of condensate per day for Petrohawk Energy Corporation (a wholly-owned subsidiary of BHP Billiton) from its production area in the Eagle Ford shale gas formation in South Texas to the Houston Ship Channel. The pipeline will consist of approximately 70 miles of new pipeline construction and 113 miles of existing natural gas pipeline that will be converted to transport crude oil and condensate. The pipeline will originate near Cuero, Texas, and extend to the Houston Ship Channel where it will initially deliver condensate to multiple terminaling facilities having access to local refineries, petrochemical plants and loading docks. We began construction on the crude oil/condensate pipeline in December 2011 and we expect to place the pipeline into service during the second quarter of 2012. When fully complete, the pipeline will have a capacity of approximately 300,000 barrels per day;
- On September 14, 2011, we announced that we will partner with Valero Energy Corporation to build the Parkway Pipeline, a new 136-mile, 16-inch diameter pipeline that will transport refined petroleum products from refineries located in Norco, Louisiana, to Plantation Pipe Line Company's petroleum transportation hub located in Collins, Mississippi. From this hub, the products will be transported by various products pipeline systems (including Plantation, our approximately 51%-owned equity investee) that serve major markets in the southeastern United States. We will operate the Parkway Pipeline and our ownership is through our 50% equity interest in Parkway Pipeline LLC, the sole owner of the Parkway Pipeline. Valero Energy Corporation owns the remaining 50% ownership interest. Pending receipt of environmental and regulatory approvals, the approximately \$220 million pipeline project is expected to be in service by mid-year 2013. The Parkway Pipeline will have an initial capacity of 110,000 barrels per day, with the ability to expand to over 200,000 barrels per day. The project is supported by a long-term throughput agreement with a credit-worthy shipper;
- As of the date of this report, construction continues on our previously announced refined petroleum products storage expansion project at our West Coast Terminals' Carson, California products terminal. The approximately \$77 million expansion project will add seven storage tanks with a combined capacity of 560,000 barrels. In October 2011, we completed and placed into service two storage tanks, and we expect to place the remaining five tanks into service in late 2012 and early 2013. We have entered into a long-term agreement with a major oil company to lease six of these tanks;
- As of the date of this report, construction continues on our West Coast Products Pipelines' approximately \$48 million expansion project at Travis Air Force Base located in Fairfield, California. As previously announced, we are constructing three 150,000 barrel storage tanks that will be used for the transportation and storage of incremental military jet fuel. Two of the three storage tanks were completed and placed into service in December 2011, and we expect to place the remaining tank into service in March 2012;
- As of the date of this report, we continue to invest more than \$35 million to further expand our renewable fuel handling capabilities at various terminal sites across the United States. We completed biodiesel blending modifications at Plantation's Collins, Mississippi hub in December 2011. These modifications allow Plantation to transport blended biodiesel to several of our existing Southeast terminal facilities. Additionally, construction continues at our Port of Tampa terminal related to our previously announced public-private partnership project with the Tampa Port Authority and CSX Corporation that will bring additional ethanol into the Tampa market via the nation's first ethanol unit train to pipeline distribution system. We expect this new ethanol hub will be operational by October 2012;
- On December 14, 2011, we announced that we will build, own and operate a petroleum condensate processing facility near our Galena Park liquids terminal located on the Houston Ship Channel. The processing facility will have an initial throughput of 25,000 barrels per day and will be designed for future expansions that will allow for throughput of up to 100,000 barrels per day. The facility will split condensate into its various components such as light and heavy naphthas, kerosene and gas oil, and through a fee structure, a major oil industry customer is underwriting the initial throughput of the facility. Our current estimate of total construction costs on the project is approximately \$130.0 million and we expect to complete construction of this facility and commence service in January 2014; and
- On December 15, 2011, we acquired a refined petroleum products terminal located on a 14-acre site in Lorton, Virginia from Motiva Enterprises, LLC for an aggregate consideration of \$12.5 million in cash. The terminal is served exclusively by the Plantation Pipeline and has storage capacity of approximately 450,000 barrels for refined petroleum products like gasoline and jet fuel.

Natural Gas Pipelines

- On January 1, 2011, Fayetteville Express Pipeline LLC began firm contract pipeline transportation service to customers on its Fayetteville Express natural gas pipeline system, a 187-mile, 42-inch diameter pipeline that provides shippers in the Arkansas Fayetteville shale gas area with takeaway natural gas capacity and further access to growing markets. We own a 50% interest in Fayetteville Express Pipeline LLC, and Energy Transfer Partners L.P. owns the remaining interest and also operates the Fayetteville Express pipeline system. Construction of the pipeline system was completed in January 2011, and total costs for the project were slightly less than \$1.0 billion (versus the original budget of \$1.3 billion);
- On April 14, 2011, our subsidiary Kinder Morgan Interstate Gas Transmission LLC completed construction and placed into service all remaining capital improvements that expanded its mainline natural gas pipeline facilities that run from Franklin to Hastings, Nebraska. The pipeline expansion and capital improvements created up to ten million cubic feet per day of natural gas capacity to serve an ethanol plant located near Aurora, Nebraska. Project construction commenced in October 2009 and total costs for the project were approximately \$18.4 million;
- In May 2011, we completed debrining a third underground storage cavern at our North Dayton natural gas storage facility located in Liberty County, Texas. The completed cavern added approximately seven billion cubic feet of working natural gas storage capacity at the facility, and the development and mining of the cavern was part of an approximately \$103 million expansion project at our North Dayton storage facility;
- On July 1, 2011, our Texas intrastate natural gas pipeline group replaced an expiring 10-year services agreement with Calpine Corporation with a new 10-year agreement that extends to July 1, 2021. Pursuant to the terms of the agreement, our intrastate group will provide Calpine approximately 300 million cubic feet per day of natural gas transport capacity and four billion cubic feet of natural gas storage capacity. Calpine will use the service to supply fuel to seven of its electricity generating facilities in the state of Texas;
- On July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC that we did not already own and a 25% equity ownership interest in EagleHawk Field Services, LLC (Petrohawk's natural gas gathering and treating business located in the Eagle Ford shale gas formation) for an aggregate consideration of \$912.1 million, consisting of \$835.1 million in cash and assumed debt of \$77.0 million (representing 50% of KinderHawk's borrowings under its bank credit facility as of July 1, 2011). We then repaid the outstanding \$154.0 million of borrowings and following this repayment, KinderHawk had no outstanding debt.

Following our acquisition of the remaining ownership interest in KinderHawk on July 1, 2011, we changed our method of accounting from the equity method to full consolidation, and due to the fact that we acquired a controlling financial interest in KinderHawk, we remeasured our previous 50% equity investment in KinderHawk to its fair value. We recognized a \$167.2 million non-cash loss as a result of this remeasurement. The loss amount represents the excess of the carrying value of our investment (\$910.2 million as of July 1, 2011) over its fair value (\$743.0 million), and we reported this loss separately within the "Other Income (Expense)" section in our accompanying consolidated statements of income for the year ended December 31, 2011. Further information on our KinderHawk operations is discussed below in "(c) Narrative Description of Business—Natural Gas Pipelines—Texas Intrastate Natural Gas Pipeline Group and Other—KinderHawk Field Services LLC;"

- On August 1, 2011, Eagle Ford Gathering LLC initiated flow on its natural gas gathering system with deliveries to Copano's natural gas processing plant located in Colorado County, Texas. Eagle Ford Gathering LLC is a joint venture that provides natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford shale gas formation. It is owned 50% by us and 50% by Copano Energy, L.L.C. Copano also serves as operator and managing member. On October 3, 2011, Eagle Ford Gathering initiated flow on its new 56-mile, 24-inch diameter crossover pipeline and a 7-mile, 20-inch diameter lateral pipeline with deliveries to Williams Partners L.P.'s Markham processing plant located in Matagorda County, Texas. The joint venture has also completed a 20-mile, 20-inch diameter pipeline to deliver natural gas to Formosa's Point Comfort plant located in Jackson County, Texas and expects initial flow of natural gas to Formosa to occur in March 2012. Including its 111 miles of 30-inch diameter and 24-inch diameter gathering pipelines, its crossover pipeline, its pipeline laterals to Williams and to Formosa, and the capacity rights it holds on certain of our natural gas pipelines, Eagle Ford Gathering has approximately 400 miles of pipelines with capacity to gather and process over 700 million cubic feet of natural gas per day. The joint venture has executed long term firm service agreements with multiple producers for the vast majority of its processing capacity, and has also executed interruptible service agreements with multiple producers under which natural gas can flow on a "as capacity is available" basis; and

- On November 30, 2011, we acquired a manufacturing complex and certain natural gas treating assets from SouthTex Treaters, Inc. for an aggregate consideration of \$178.5 million, consisting of \$151.5 million in cash and assumed liabilities of \$27.0 million. SouthTex Treaters, Inc. is a leading manufacturer, designer and fabricator of natural gas treating plants that are used to remove impurities (carbon dioxide and hydrogen sulfide) from natural gas before it is delivered into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. The acquisition complemented and expanded our existing natural gas treating business.

CO₂

- On November 17, 2011, we announced that we had entered into a purchase and sale agreement with a subsidiary of Enhanced Oil Resources to acquire a carbon dioxide source field and related assets located in Apache County, Arizona, and Catron County, New Mexico, for approximately \$30 million in cash. The acquisition includes all of Enhanced Oil's rights, title, and interest in the carbon dioxide and helium located in the St. Johns gas unit and the Cottonwood Canyon carbon dioxide unit, and we expect that this acquisition will provide us with opportunities to further grow our existing carbon dioxide business. The transaction closed on January 31, 2012;
- During 2011, we activated 15 additional patterns at our carbon dioxide flood in the Katz oil field located near Knox City, Texas. The flood is part of our previously announced Eastern Shelf Pipeline project in the eastern Permian Basin area of Texas. The approximately \$230 million project also involved the installation of a 91-mile, 10-inch carbon dioxide distribution pipeline that begins near Snyder, Texas and ends west of Knox City. We began injecting carbon dioxide into the Katz field in December 2010 and currently, we are producing approximately 1,400 barrels of crude oil per day from the Katz field. The development of the carbon dioxide flood in the Katz field is projected to produce an incremental 25 million barrels of oil over the next 15 to 20 years and will provide a platform for future enhanced oil recovery operations in the region; and
- On January 18, 2012, we announced an approximately \$255 million investment to expand the carbon dioxide capacity of our approximately 87%-owned Doe Canyon Deep unit in southwestern Colorado. The expansion project will include the installation of both primary and booster compression and is expected to increase Doe Canyon's current production rate from 105 million cubic feet of carbon dioxide per day to 170 million cubic feet per day. We expect to begin construction in the second quarter of 2012, to complete and place in service the primary compression in the fourth quarter of 2013, and complete the booster compression in the second quarter of 2014. Additionally, we plan to drill approximately 19 more wells during the next ten years, with three wells scheduled for completion in 2012.

Terminals

- On January 3, 2011 and December 28, 2011, we made two separate \$50 million preferred equity investments in Watco Companies, LLC, the largest privately held short line railroad company in the United States. Watco also operates transload/intermodal and mechanical services divisions. Our investments provided capital to Watco for further expansion of specific projects, and for pending acquisitions, including Watco's previously announced acquisitions of both a controlling interest in the Wisconsin & Southern Railroad and the assets of Birmingham Southern Railway. Our investment in Watco provides our customers access to more transportation related services and also offers us the opportunity to share in additional growth opportunities through new projects, such as crude oil unit train operations and incremental business at our terminal storage facilities. Pursuant to the terms of our investments, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and we participate partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's Board of Managers. As of December 31, 2011, our net equity investment totaled \$101.7 million;
- In January 2011, we completed construction of an approximately \$16.2 million railcar loop track at our Deepwater petroleum coke terminal facility located in Pasadena, Texas. The track is used to transport a major petroleum coke producer's volumes to the facility;
- On February 17, 2011, our subsidiary Kinder Morgan Cushing LLC, Deeprock Energy Resources, LLC and Mecuria Energy Trading, Inc., entered into formal agreements for a crude oil storage joint venture located in Cushing, Oklahoma. On this date, we contributed \$15.9 million for a 50% ownership interest in the Deeprock North, LLC joint venture, which operated an existing crude oil tank farm that had storage capacity of one million barrels. During 2011, we contributed an additional \$7.7 million for our proportionate share of costs related to the construction of three new storage tanks that provide for incremental storage capacity of 750,000 barrels. The new

tanks were completed and placed in service during the fourth quarter of 2011. Deeprock Energy operates and owns a 12.02% member interest in the joint venture, and Mecuria owns the remaining 37.98% member interest and is the anchor tenant for the joint venture's crude oil capacity for the next five years with an option to extend. As of December 31, 2011, our net equity investment in Deeprock North, LLC totaled \$24.0 million;

- On February 24, 2011 and October 3, 2011, respectively, in order to capitalize on increasing demand for both coal export activity and domestic coal use, we entered into two separate agreements to expand our coal terminal operations at our International Marine Terminals facility (IMT), a multi-product, import-export facility located in Port Sulphur, Louisiana and owned 66 2/3% by us. In February 2011, we entered into a 15-year services agreement with Massey Coal, a division of Alpha Natural Resources, to handle up to six million tons of coal annually. The majority of the coal that will pass through IMT will originate from Massey's Central Appalachia mines, be transported to IMT by river barges, and then offloaded and stored before being loaded onto ocean vessels for export to foreign markets. We anticipate a minimum throughput tonnage increase of four million tons per year related to this agreement. Secondly, in October 2011, we entered into a long-term agreement with Progress Energy Florida to handle up to four million tons of coal per year at IMT. This agreement will commence in early 2013, and provides Progress Energy with options to extend the agreement for up to 20 years. Together, we and our remaining one-third partner at IMT are investing approximately \$114 million to expand and upgrade the facility to enable it to handle the incremental coal volumes related to these two agreements. We expect the terminal upgrades to be completed by mid-2013;
- In March 2011, we completed construction of our previously announced Deer Park Rail Terminal (DPRT) and related ethanol handling assets at our Pasadena, Texas terminal located along the Houston Ship Channel. The approximately \$19 million project included building a new ethanol unit train facility with space for multiple unit trains, an offloading rail rack for unit trains of approximately 100 railcars, and an 80,000 barrel ethanol storage tank. As part of the expansion, we also extended an existing pipeline by approximately 2.4 miles so that ethanol can be moved from DPRT to our nearby Pasadena liquids terminal for either storage or blending at the terminal's truck rack. The project is supported by long-term customer contracts;
- In March 2011, we entered into an agreement with a large western coal producer to handle up to 2.2 million tons of Colorado coal annually at our Houston, Texas bulk terminal facility located on the Houston Ship Channel. Unit trains will transport bituminous coal from Colorado mines to our Houston bulk facility, where the coal will be offloaded and stored before being loaded onto ocean vessels. We also announced an approximately \$18 million investment to increase the facility's coal handling capability by adding rail and conveying equipment, and outbound equipment needed to load coal onto ships. We began handling coal for this new contract in July 2011, marking the first time that western coal was exported from the Port of Houston;
- On June 10, 2011, we acquired a newly constructed petroleum coke terminal located in Port Arthur, Texas from TGS Development, L.P. (TGSD) for an aggregate consideration of \$74.1 million, consisting of \$42.9 million in cash, \$23.7 million in common units, and an obligation to pay additional consideration of \$7.5 million. We estimate our remaining \$7.5 million obligation will be paid to TGSD approximately one year from the closing (in May or June 2012), and will be settled in a combination of cash and common units, depending on TGSD's election. We operate the terminal, which receives petroleum coke from Total Petrochemicals USA Inc.'s Port Arthur refinery, and we provide conveying, storage and ship loading services to Total pursuant to a 25-year services agreement. The refinery is expected to produce more than one million tons of petroleum coke annually;
- On July 20, 2011, we announced an incremental \$8.3 million investment at our DPRT (described above) which will add additional ethanol handling and storage capabilities. The expansion includes building a second 80,000 barrel storage tank and related facilities. We expect this project will be completed in the first quarter of 2012;
- In September 2011, we completed an approximately \$14 million expansion of our Philadelphia, Pennsylvania liquids terminal to provide storage and handling services to accommodate a large chemical company. The project involved upgrading existing tank and pipeline systems and installing a new marine flare unit. The project is secured with a five-year customer agreement;
- In September 2011, we completed an approximately \$62 million expansion of our Carteret, New Jersey liquids terminal that added 1.04 million barrels of new petroleum storage tank capacity. In July 2009, we entered into an agreement with a major oil company for this additional capacity. The project involved the construction of seven new blending tanks, consisting of three 125,000 barrel tanks and four 165,000 barrel storage tanks. All of the tanks can be used for gasoline blending, and some have built-in flexibility for either ethanol or distillate service;

- On November 8, 2011, we announced our equity participation in Battleground Oil Specialty Terminal Company LLC (BOSTCO), and we paid a combined \$12.0 million to acquire our initial 50% Class A member interest (consisting of \$11.6 million paid in October 2011 and \$0.4 million of pre-development costs incurred and paid for during 2010). On December 29, 2011, we acquired the remaining 50% Class A member interest in BOSTCO that we did not already own from TransMontaigne Partners, L.P. for an aggregate consideration of \$8.1 million in cash (net of an acquired cash balance of \$9.9 million). TransMontaigne also received a transferrable option to buy 50% of our ownership interest at any time prior to January 20, 2013; however, we are currently unable to predict whether it will exercise this purchase option.

BOSTCO will construct, own and operate an approximately \$430 million oil terminal located on the Houston Ship Channel. Phase I of the project includes the design and construction of 52 tanks with combined storage capacity of approximately 6.6 million barrels for handling residual fuel, feedstocks, distillates and other black oils. BOSTCO will initially be a water-in, water-out facility with the capability of handling ships with large drafts up to 45 feet, and we have executed terminal service contracts or letters of intent with customers for almost all of the Phase I storage capacity;

- On November 30, 2011, we announced an approximately \$212 million investment to construct seven tanks with a storage capacity of approximately 2.4 million barrels for crude oil and condensate at our Trans Mountain pipeline terminal located near Edmonton, Alberta, Canada. We have entered into long-term contracts with customers to support this expansion, which will set the framework for two additional phases that will ultimately allow for up to six million barrels of dedicated storage. Previously, we received National Energy Board (Canada) approval to construct merchant and regulated tanks at our Edmonton terminal, and we intend to commence construction in early 2012 following receipt of other supporting permits. We anticipate that the new tanks will be placed in service in late 2013;
- On January 18, 2012, we announced that we had entered into a long-term agreement with a major Canadian oil producer to support an approximately \$8.5 million expansion of pipeline feeder connections into our Kinder Morgan North 40 terminal, a crude oil tank farm located in Strathcona County, just east of Edmonton, Alberta, Canada; and
- On January 24, 2012, we announced plans to invest an additional \$140 million to further expand our coal handling export facilities along the Gulf Coast. Concurrently, Arch Coal Company signed a long-term throughput agreement with us that will help support this expansion, which we anticipate to complete in the second quarter of 2014. Upon completion of the proposed terminal upgrades, and subject to certain rail service agreements, Arch will ship coal at guaranteed minimum volume levels through our owned terminal facilities. In addition, we and Arch are in final discussions to include, in the throughput agreement, port space for coal shipments at our coal export facilities located on the East Coast and at our IMT facility, which when combined with our Gulf Coast expansions, will provide incremental port capacity for Arch's growing seaborne coal volumes. We are also extending certain existing long-term coal handling agreements with Arch at our coal facilities located in the state of Illinois.

Kinder Morgan Canada

- From October 20, 2011 until February 16, 2012, our Trans Mountain pipeline system conducted a binding public open season to assess shipper interest for a proposed system expansion. Originating in Edmonton, Alberta, our Trans Mountain system is currently designed to carry up to 300,000 barrels per day of crude oil and refined petroleum products to destinations in the northwest United States and on the west coast of British Columbia. Based on shipper response, we would construct a twin pipeline that could boost system capacity to over 600,000 barrels per day. Our current estimate of total construction costs on the project is approximately \$3.8 billion.

Financings

- On March 4, 2011, we issued a total of \$1.1 billion in principal amount of senior notes in two separate series, consisting of \$500 million of 3.50% notes due March 1, 2016, and \$600 million of 6.375% notes due March 1, 2041. We used the net proceeds received from this debt offering to reduce the borrowings under our commercial paper program;
- On March 15, 2011, we paid \$700 million to retire the principal amount of our 6.75% senior notes that matured on that date;

- On July 1, 2011, we amended our \$2.0 billion three-year, senior unsecured revolving credit facility to, among other things, (i) allow for borrowings of up to \$2.2 billion; (ii) extend the maturity of the credit facility from June 23, 2013 to July 1, 2016; (iii) permit an amendment to allow for borrowings of up to \$2.5 billion; and (iv) decrease the interest rates and commitment fees for borrowings under this facility. The credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit facility can be used for general partnership purposes and as a backup for our \$2.2 billion commercial paper program;
- On August 17, 2011, we issued a total of \$750 million in principal amount of senior notes in two separate series, consisting of \$375 million of 4.15% notes due March 1, 2022, and \$375 million of 5.625% notes due September 1, 2041. We used the net proceeds received from this debt offering to reduce the borrowings under our commercial paper program;
- In August 2011, we terminated two existing fixed-to-variable interest rate swap agreements in two separate transactions. These swap agreements had a combined notional principal amount of \$200 million, and we received combined proceeds of \$73.0 million from the early termination of these swap agreements; and
- In 2011, we issued 13,469,708 common units for \$955.3 million in cash, described following. We used the net proceeds received from the issuance of these common units to reduce the borrowings under our commercial paper program:

In June 2011, we completed a public offering of 7,705,000 of our common units at a price of \$71.44 per unit. After commissions and underwriting expenses, we received net proceeds of \$533.9 million for the issuance of these common units; and

During 2011, we issued 5,764,708 of our common units pursuant to our equity distribution agreement with UBS Securities LLC. After commissions, we received net proceeds of \$421.4 million from the issuance of these common units.

2012 Outlook

- As previously announced, we anticipate that for the year 2012, (i) we will declare cash distributions of \$4.98 per unit, an 8% increase over our cash distributions of \$4.61 per unit for 2011; (ii) our business segments will generate approximately \$4.4 billion in earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments and our share of all non-cash depreciation, depletion and amortization expenses of certain joint ventures accounted for under the equity-method of accounting; (iii) we will distribute approximately \$1.7 billion to our limited partners; (iv) we will produce excess cash flow of \$71.0 million above our cash distribution target of \$4.98 per unit; and (v) we will invest approximately \$1.7 billion for our capital expansion program (including small acquisitions and contributions to joint ventures). Our anticipated 2012 expansion investment will help drive earnings and cash flow growth in 2012 and beyond, and we estimate that approximately \$490 million of the equity required for our 2012 investment program will be funded by cash retained as a function of KMR distributions being paid in additional units rather than in cash. In 2011, our capital expansion program was approximately \$2.6 billion—including discretionary capital spending, equity contributions to our equity investees, and acquisition cash expenditures.

Our expectations assume an average West Texas Intermediate (WTI) crude oil price of approximately \$93.75 per barrel in 2012. Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO₂ business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. We hedge the majority of our crude oil production, but do have exposure to unhedged volumes, the majority of which are natural gas liquids volumes. For 2012, we expect that every \$1 change in the average WTI crude oil price per barrel will impact our CO₂ segment's cash flows by approximately \$5.8 million (or slightly over 0.1% of our combined business segments' anticipated earnings before depreciation, depletion and amortization expenses).

(b) Financial Information about Segments

For financial information on our five reportable business segments, see Note 15 to our consolidated financial statements included elsewhere in this report.

(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
- maximize the benefits of our financial structure to create and return value to our unitholders.

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, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions and approval of the parties’ respective boards of directors. While there are currently no unannounced purchase agreements for the acquisition 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

We own and manage a diversified portfolio of energy transportation and storage assets. Our operations are conducted through our five operating limited partnerships and their subsidiaries and are grouped into five reportable business segments. These segments are as follows:

- Products Pipelines—which consists of approximately 8,400 miles of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus approximately 60 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the United States;
- Natural Gas Pipelines—which consists of approximately 16,200 miles of natural gas transmission pipelines and gathering lines, plus natural gas storage, treating and processing facilities, through which natural gas is gathered, transported, stored, treated, processed and sold;
- CO₂— which produces, markets and transports, through approximately 2,000 miles of pipelines, carbon dioxide to oil fields that use carbon dioxide to increase production of oil; owns interests in and/or operates eight oil fields in West Texas; and owns and operates a 450-mile crude oil pipeline system in West Texas;
- Terminals—which consists of approximately 115 owned or operated liquids and bulk terminal facilities and approximately 35 rail transloading and materials handling facilities located throughout the United States and portions of Canada, which together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products for customers across the United States and Canada; and
- Kinder Morgan Canada—which transports crude oil and refined petroleum products through over 2,500 miles of pipelines from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States; plus five associated product terminal facilities.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products and natural gas liquids pipelines and associated terminals, Southeast terminals, and our transmix processing facilities.

West Coast Products Pipelines

Our West Coast Products Pipelines include our SFPP, L.P. operations (often referred to in this report as our Pacific operations), our Calnev pipeline operations, and our West Coast Terminals operations. The assets include interstate common carrier pipelines regulated by the FERC, intrastate pipelines in the state of California regulated by the California Public Utilities Commission, and certain non rate-regulated operations and terminal facilities.

Our Pacific operations serve six western states with approximately 2,500 miles of refined petroleum products pipelines and related terminal facilities that provide refined products to major population centers in the United States, including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. In 2011, our Pacific operations' mainline pipeline system transported approximately 1,071,400 barrels per day of refined products, with the product mix being approximately 59% gasoline, 24% diesel fuel, and 17% jet fuel.

Our Calnev pipeline system consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from our facilities at Colton, California to Las Vegas, Nevada. The pipeline serves the Mojave Desert through deliveries to a terminal at Barstow, California and two nearby major railroad yards. It also serves Nellis Air Force Base, located in Las Vegas, and also includes approximately 55 miles of pipeline serving Edwards Air Force Base in California. In 2011, our Calnev pipeline system transported approximately 118,800 barrels per day of refined products, with the product mix being approximately 41% gasoline, 33% diesel fuel, and 26% jet fuel.

Our West Coast Products Pipelines operations include 15 truck-loading terminals (13 on our Pacific operations and two on Calnev) with an aggregate usable tankage capacity of approximately 15.3 million barrels. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.

Our West Coast Terminals are fee-based terminals located in the Seattle, Portland, San Francisco and Los Angeles areas along the west coast of the United States with a combined total capacity of approximately 9.1 million barrels of storage for both petroleum products and chemicals. Our West Coast Products Pipelines and associated West Coast Terminals together handled 17.6 million barrels of ethanol in 2011.

Combined, our West Coast Products Pipelines operations' pipelines transport approximately 1.2 million barrels per day of refined petroleum products, providing pipeline service to approximately 29 customer-owned terminals, 11 commercial airports and 15 military bases. The pipeline systems serve approximately 70 shippers in the refined petroleum products market, the largest customers being major petroleum companies, independent refiners, and the United States military. The majority of refined products supplied to our West Coast Product Pipelines come from the major refining centers around Los Angeles, San Francisco, West Texas and Puget Sound, as well as from waterborne terminals and connecting pipelines located near these refining centers.

Plantation Pipe Line Company

We own approximately 51% of Plantation Pipe Line Company, the sole owner of the approximately 3,100-mile refined petroleum products Plantation pipeline system serving the southeastern United States. We operate the system pursuant to agreements with Plantation and its wholly-owned subsidiary, Plantation Services LLC. The Plantation pipeline system originates in Louisiana and terminates in the Washington, D.C. area. It connects to approximately 130 shipper delivery terminals throughout eight states and serves as a common carrier of refined petroleum products to various metropolitan areas, including Birmingham, Alabama; Atlanta, Georgia; Charlotte, North Carolina; and the Washington, D.C. area. An affiliate of ExxonMobil Corporation owns the remaining approximately 49% ownership interest, and ExxonMobil has historically been one of the largest shippers on the Plantation system both in terms of volumes and revenues. In 2011, Plantation delivered approximately 518,000 barrels per day of refined petroleum products, with the product mix being approximately 67% gasoline, 20% diesel fuel, and 13% jet fuel.

Products shipped on Plantation originate at various Gulf Coast refineries from which major integrated oil companies and independent refineries and wholesalers ship refined petroleum products, from other products pipeline systems, and via marine facilities located along the Mississippi River. Plantation ships products for approximately 30 companies to terminals throughout the southeastern United States. Plantation's principal customers are Gulf Coast refining and marketing companies, and fuel wholesalers.

Central Florida Pipeline

Our Central Florida pipeline system consists of a 110-mile, 16-inch diameter pipeline that transports gasoline and ethanol, and an 85-mile, 10-inch diameter pipeline that transports diesel fuel and jet fuel from Tampa to Orlando. Our Central Florida pipeline operations also include two separate liquids terminals located in Tampa and Taft, Florida, which we own and operate.

In addition to being connected to our Tampa terminal, the Central Florida pipeline system is connected to terminals owned and operated by TransMontaigne, Citgo, BP, and Marathon Petroleum. The 10-inch diameter pipeline is connected to our Taft terminal (located near Orlando), has an intermediate delivery point at Intercession City, Florida, and is also the sole pipeline supplying jet fuel to the Orlando International Airport in Orlando, Florida. In 2011, the pipeline system transported approximately 93,000 barrels per day of refined products, with the product mix being approximately 69% gasoline and ethanol, 11% diesel fuel, and 20% jet fuel.

Our Tampa terminal contains approximately 1.6 million barrels of refined products storage capacity and is connected to two ship dock facilities in the Port of Tampa. Our Taft terminal contains approximately 0.8 million barrels of storage capacity, for gasoline, ethanol and diesel fuel for further movement into trucks.

Cochin Pipeline System

Our Cochin pipeline system consists of an approximately 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta and Windsor, Ontario, along with five terminals. The pipeline operates on a batched basis and has an estimated system capacity of approximately 70,000 barrels per day. It includes 31 pump stations spaced at 60 mile intervals and five United States propane terminals. Underground storage is available at Fort Saskatchewan, Alberta and Windsor, Ontario through third parties. The pipeline traverses three provinces in Canada and seven states in the United States and can transport propane, butane and natural gas liquids to the midwestern United States and eastern Canadian petrochemical and fuel markets. In 2011, the pipeline system transported approximately 26,500 barrels per day of propane, and in 2012, we expect to begin transporting additional natural gas liquids products.

Cypress Pipeline

We own 50% of Cypress Interstate Pipeline LLC, the sole owner of the Cypress pipeline system. We operate the system pursuant to a long-term agreement. The Cypress pipeline is an interstate common carrier natural gas liquids pipeline originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a connection with Westlake Chemical Corporation, a major petrochemical producer in the Lake Charles, Louisiana area. Mont Belvieu, located approximately 20 miles east of Houston, is the largest hub for natural gas liquids gathering, transportation, fractionation and storage in the United States. The Cypress pipeline system has a current capacity of approximately 55,000 barrels per day for natural gas liquids. In 2011, the system transported approximately 45,000 barrels per day.

Southeast Terminals

Our Southeast terminal operations consist of 27 high-quality, liquid petroleum products terminals located along the Plantation/Colonial pipeline corridor in the Southeastern United States. The marketing activities of our Southeast terminal operations are focused on the Southeastern United States from Mississippi through Virginia, including Tennessee. The primary function involves the receipt of petroleum products from common carrier pipelines, short-term storage in terminal tankage, and subsequent loading onto tank trucks. Combined, our Southeast terminals have a total storage capacity of approximately 9.1 million barrels. In 2011, these terminals transferred approximately 353,000 barrels of refined products per day and together handled 9.2 million barrels of ethanol.

Transmix Operations

Our Transmix operations include the processing of petroleum pipeline transmix, a blend of dissimilar refined petroleum products that have become co-mingled in the pipeline transportation process. During pipeline transportation, different products are transported through the pipelines abutting each other, and generate a volume of different mixed products called transmix. We process and separate pipeline transmix into pipeline-quality gasoline and light distillate products at six separate processing facilities located in Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; Wood River, Illinois; and Greensboro, North Carolina. Combined, our transmix facilities processed approximately 10.6 million barrels of transmix in 2011.

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.

Natural Gas Pipelines

Our Natural Gas Pipelines segment contains both interstate and intrastate pipelines. Its primary businesses consist of natural gas sales, transportation, storage, gathering, processing and treating. Within this segment, we own approximately 16,300 miles of natural gas pipelines and associated storage and supply lines that are strategically located at the center of the North American pipeline grid. Our transportation network provides access to the major gas supply areas in the western United States, Texas and the Midwest, as well as major consumer markets.

Texas Intrastate Natural Gas Pipeline Group and Other

Texas Intrastate Natural Gas Pipeline Group

Our Texas intrastate natural gas pipeline group, which operates primarily along the Texas Gulf Coast, consists of the following four natural gas pipeline systems: (i) our Kinder Morgan Texas Pipeline; (ii) our Kinder Morgan Tejas Pipeline; (iii) our Mier-Monterrey Mexico Pipeline; and (iv) our Kinder Morgan North Texas Pipeline.

The two largest systems in the group are our Kinder Morgan Texas Pipeline and our Kinder Morgan Tejas Pipeline. These pipelines essentially operate as a single pipeline system, providing customers and suppliers with improved flexibility and reliability. The combined system includes approximately 6,000 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 5.5 billion cubic feet per day of natural gas and approximately 144 billion cubic feet of on-system natural gas storage capacity, including 11 billion cubic feet contracted from a third party (which will be reduced to 5 billion cubic feet in April 2012). In addition, the combined system (i) has facilities to both treat approximately 180 million cubic feet per day of natural gas for carbon dioxide and hydrogen sulfide removal, and to process approximately 65 million cubic feet per day of natural gas for liquids extraction; and (ii) holds contractual rights to process natural gas at certain third party facilities.

Our Mier-Monterrey Pipeline consists of a 95-mile natural gas pipeline that stretches from the international border between the United States and Mexico in Starr County, Texas, to Monterrey, Mexico and can transport up to 375 million cubic feet per day. The pipeline connects to a 1,000-megawatt power plant complex and to the Pemex natural gas transportation system. We have entered into a long-term contract (expiring in 2018) with Pemex, which has subscribed for all of the pipeline's capacity.

Our Kinder Morgan North Texas Pipeline consists of an 82-mile pipeline that transports natural gas from an interconnect with the facilities of Natural Gas Pipeline Company of America LLC (a 20%-owned equity investee of KMI and referred to in this report as NGPL) in Lamar County, Texas to a 1,750-megawatt electricity generating facility located in Forney, Texas, 15 miles east of Dallas, Texas. It has the capacity to transport 325 million cubic feet per day of natural gas and is fully subscribed under a long-term contract that expires in 2032. The system is bi-directional, permitting deliveries of additional supply from the Barnett Shale area to NGPL's pipeline as well as power plants in the area.

Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in our Texas intrastate natural gas pipeline group's market area is primarily composed of industrial (including on-site cogeneration facilities), merchant and utility power, and local natural gas distribution consumption. The industrial demand is primarily year-round load. Merchant and utility power demand peaks in the summer months and is complemented by local natural gas distribution demand that peaks in the winter months.

Collectively, our Texas intrastate natural gas pipeline system primarily serves the Texas Gulf Coast by selling, transporting, processing and treating natural gas from multiple onshore and offshore supply sources to serve the Houston/Beaumont/Port Arthur/Austin industrial markets, local natural gas distribution utilities, electric utilities and merchant power generation markets. It serves as a buyer and seller of natural gas, as well as a transporter of natural gas. In 2011, the four natural gas pipeline systems in our Texas intrastate group provided an average of approximately 2.23 billion cubic feet per day of natural gas transport services. The Texas intrastate group also sold approximately 804.7 billion cubic feet of natural gas in 2011.

The purchases and sales of natural gas are primarily priced with reference to market prices in the consuming region of the system. The difference between the purchase and sale prices is the rough equivalent of a transportation fee and fuel costs. Generally, we purchase natural gas directly from producers with reserves connected to our intrastate natural gas system in South Texas, East Texas, West Texas, and along the Texas Gulf Coast. In addition, we also purchase gas at interconnects with third-party interstate and intrastate pipelines. While our intrastate group does not produce gas, it does maintain an active well connection program in order to offset natural declines in production along its system and to secure supplies for additional demand in its market area. Our intrastate system has access to both onshore and offshore sources of supply, and is well positioned to interconnect with liquefied natural gas projects currently under development by others along the Texas Gulf Coast. Our intrastate group also has access to markets within and outside of Texas through interconnections with numerous interstate natural gas pipelines.

Kinder Morgan Treating L.P.

Our subsidiary, Kinder Morgan Treating, L.P., owns and operates (or leases to producers for operation) treating plants that remove impurities (such as carbon dioxide and hydrogen sulfide) and hydrocarbon liquids from natural gas before it is delivered into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. Additionally, its subsidiary KM Treating Production LLC designs, constructs, and sells custom and stock natural gas treating plants. Combined, our rental fleet of treating assets include approximately 213 natural gas amine-treating plants, approximately 56 hydrocarbon dew point control plants, and more than 140 mechanical refrigeration units that are used to remove impurities and hydrocarbon liquids from natural gas streams prior to entering transmission pipelines.

In addition, on November 30, 2011, we acquired certain natural gas treating assets from SouthTex Treating, Inc., a leading manufacturer, designer and fabricator of natural gas treating plants. Further information about this acquisition is discussed above in “—(a) General Development of Business—Recent Developments—Natural Gas Pipelines.”

KinderHawk Field Services LLC and EagleHawk Field Services LLC

On July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC that we did not already own and a 25% equity ownership interest in EagleHawk Field Services LLC. Further information about this acquisition is discussed above in “—(a) General Development of Business—Recent Developments—Natural Gas Pipelines.” On August 25, 2011, mining and oil company BHP Billiton completed its previously announced acquisition of Petrohawk Energy Corporation through a short-form merger under Delaware law. The merger was closed with Petrohawk being the surviving corporation as a wholly owned subsidiary of BHP Billiton. The acquisition will not affect the terms of our contracts with Petrohawk.

KinderHawk Field Services LLC gathers and treats natural gas in the Haynesville shale gas formation located in northwest Louisiana. Its assets currently consist of more than 450 miles of natural gas gathering pipeline currently in service, with average throughput of approximately 1.1 billion cubic feet per day of natural gas. Ultimately, KinderHawk is expected to have approximately 2.0 billion cubic feet per day of throughput capacity, which will make it one of the largest natural gas gathering and treating systems in the United States. Additionally, the system’s natural gas amine treating plants have a current capacity of approximately 2,600 gallons per minute.

KinderHawk owns life of lease dedications to gather and treat all of Petrohawk’s operated Haynesville and Bossier shale gas production in northwest Louisiana at agreed upon rates, as well as minimum volume commitments from Petrohawk for a five year term that expires in May 2015. During 2011, KinderHawk executed firm gathering and treating agreements with a third-party producer for the long-term dedication of five sections. KinderHawk also holds additional third-party gas gathering and treating commitments. In total, these contracts provide for the dedication of 36 sections, from four shippers, for three to ten years.

EagleHawk Field Services LLC provides natural gas gathering and treating services in the Eagle Ford shale formation in South Texas. Petrohawk operates EagleHawk Field Services LLC and owns the remaining 75% ownership interest. EagleHawk owns two midstream gathering systems in and around Petrohawk’s Hawkville and Black Hawk areas of the Eagle Ford shale formation and combined, its assets consist of more than 280 miles of gas gathering pipelines and approximately 140 miles of condensate lines. It also has a life of lease dedication of Petrohawk’s Eagle Ford reserves that will provide Petrohawk and other Eagle Ford producers with natural gas and condensate gathering, treating and condensate stabilization services.

Endeavor Gathering LLC

We own a 40% equity interest in Endeavor Gathering LLC, which provides natural gas gathering service to GMX Resources' exploration and production activities in its Cotton Valley Sands and Haynesville/Bossier Shale horizontal well developments located in East Texas. GMX Resources, Inc. operates and owns the remaining 60% ownership interest in Endeavor Gathering LLC. Endeavor's gathering system consists of over 100 miles of gathering lines and 25,000 horsepower of compressors that collect and compress natural gas from GMX Resources' operated natural gas production from wells located in its core area. The natural gas gathering system has takeaway capacity of approximately 115 million cubic feet per day.

Eagle Ford Gathering LLC

We own a 50% equity interest in Eagle Ford Gathering LLC, which provides natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford shale gas formation in south Texas. Further information about Eagle Ford Gathering LLC is discussed above in “—(a) General Development of Business—Recent Developments—Natural Gas Pipelines.”

Upstream Operations

Our Natural Gas Pipelines' upstream operations consist of our Casper and Douglas, Wyoming natural gas processing operations and our 49% ownership interest in the Red Cedar Gas Gathering Company. We own and operate our Casper and Douglas, Wyoming natural gas processing plants, and combined, these plants have the capacity to process up to 185 million cubic feet per day of natural gas depending on raw gas quality. Casper and Douglas are the only natural gas processing plants which provide straddle processing of natural gas flowing into our Kinder Morgan Interstate Gas Transmission LLC pipeline system. We also own the operations of a carbon dioxide/sulfur treating facility located in the West Frenchie Draw field of the Wind River Basin of Wyoming, and we include this facility as part of our Casper and Douglas operations. The West Frenchie Draw treating facility has a capacity of 50 million cubic feet per day of natural gas.

We own a 49% equity interest in the Red Cedar Gathering Company, a joint venture organized in August 1994 and referred to in this report as Red Cedar. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar's natural gas gathering system currently consists of approximately 750 miles of gathering pipeline connecting more than 900 producing wells, 104,600 horsepower of compression at 22 field compressor stations and three carbon dioxide treating plants. The capacity and throughput of the Red Cedar gathering system is approximately 600 million cubic feet per day of natural gas.

Western Interstate Natural Gas Pipeline Group

Our Western interstate natural gas pipeline group, which operates primarily along the Rocky Mountain region of the Western portion of the United States, consists of the following three natural gas pipeline systems: (i) Kinder Morgan Interstate Gas Transmission Pipeline; (ii) TransColorado Pipeline; and (iii) our 50% ownership interest in the Rockies Express Pipeline.

Kinder Morgan Interstate Gas Transmission LLC

Our subsidiary, Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIT, owns approximately 5,100 miles of transmission lines in Wyoming, Colorado, Kansas, Missouri and Nebraska. Our KMIT pipeline system is powered by 23 transmission and storage compressor stations having approximately 155,000 horsepower. KMIT also owns the Huntsman natural gas storage facility, located in Cheyenne County, Nebraska, which has approximately 35 billion cubic feet of total capacity, consisting of 15 billion cubic feet of working capacity and 20 billion cubic feet of cushion gas. KMIT has 11 billion cubic feet of firm capacity commitments and provides for withdrawals of up to 179 million cubic feet of natural gas per day.

Under transportation agreements and FERC tariff provisions, KMIT offers its customers firm and interruptible transportation and storage services, including no-notice service and park and loan services. KMIT also has the authority to make gas purchases and sales, as needed for system operations, pursuant to its currently effective FERC natural gas tariff. Our KMIT system also offers its Cheyenne Market Center service, which provides nominated storage and transportation service between its Huntsman storage field and multiple interconnecting pipelines at the Cheyenne Hub,

located in Weld County, Colorado. Additionally, our KMIT pipeline system includes the Colorado Lateral, which is a 41-mile, 12-inch pipeline extending from the Cheyenne Hub southward to the Greeley, Colorado area. In 2011, KMIT transported an average of approximately 451 million cubic feet per day of natural gas.

TransColorado Gas Transmission Company LLC

Our subsidiary, TransColorado Gas Transmission Company LLC, referred to in this report as TransColorado, owns a 300-mile interstate natural gas pipeline that extends from approximately 20 miles southwest of Meeker, Colorado to the Blanco Hub near Bloomfield, New Mexico. It has multiple points of interconnection with various interstate and intrastate pipelines, gathering systems, and local distribution companies. Our TransColorado pipeline system is powered by eight compressor stations having an aggregate of approximately 39,000 horsepower. The system has a pipeline capacity of 1.0 billion cubic feet per day of natural gas and it has the ability to flow gas south or north. In 2011, our TransColorado pipeline system transported an average of approximately 420 million cubic feet per day of natural gas.

Our TransColorado pipeline system receives natural gas from a single coal seam natural gas treating plant, located in the San Juan Basin of Colorado, and from pipeline, processing plant and gathering system interconnections within the Paradox and Piceance Basins of western Colorado. It provides transportation services to third-party natural gas producers, marketers, gathering companies, local distribution companies and other shippers. Pursuant to transportation agreements and FERC tariff provisions, TransColorado offers its customers firm and interruptible transportation and interruptible peak and loan services. TransColorado also has the authority to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure.

Rockies Express Pipeline

We operate and own 50% of the 1,679-mile Rockies Express natural gas pipeline system, one of the largest natural gas pipelines constructed in North America in the last 25 years. The Rockies Express system consists of the following three pipeline segments: (i) a 327-mile pipeline that extends from the Meeker Hub in northwest Colorado, across southern Wyoming to the Cheyenne Hub in Weld County, Colorado; (ii) a 713-mile pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri; and (iii) a 639-mile pipeline from Audrain County, Missouri to Clarington, Ohio. Our ownership is through our 50% equity interest in Rockies Express Pipeline LLC, the sole owner of the Rockies Express pipeline system. Sempra Pipelines & Storage, a unit of Sempra Energy, and ConocoPhillips each own 25% of Rockies Express Pipeline LLC.

The Rockies Express pipeline system is powered by 18 compressor stations totaling approximately 427,000 horsepower. The system is capable of transporting 2.0 billion cubic feet per day of natural gas from Meeker, Colorado to the Cheyenne Market Hub in northeastern Colorado and 1.8 billion cubic feet per day from the Cheyenne Hub to the Clarington Hub in Monroe County in eastern Ohio. Capacity on the Rockies Express system is nearly fully contracted under ten year firm service agreements with producers from the Rocky Mountain supply basin. These agreements provide the pipeline with fixed monthly reservation revenues for the primary term of such contracts through 2019, with the exception of one agreement representing approximately 10% of the pipeline capacity that grants a shipper the one-time option to terminate effective late 2014. With its connections to numerous other pipeline systems along its route, the Rockies Express system has access to almost all of the major gas supply basins in Wyoming, Colorado and eastern Utah. Rockies Express is capable of delivering gas to multiple markets along its pipeline system, primarily through interconnects with other interstate pipeline companies and direct connects to local distribution companies.

Central Interstate Natural Gas Pipeline Group

Our Central interstate natural gas pipeline group, which operates primarily in the Mid-Continent region of the United States, consists of the following four natural gas pipeline systems: (i) Trailblazer Pipeline; (ii) Kinder Morgan Louisiana Pipeline; (iii) our 50% ownership interest in the Midcontinent Express Pipeline; and (iv) our 50% ownership interest in the Fayetteville Express Pipeline.

Trailblazer Pipeline Company LLC

Our subsidiary, Trailblazer Pipeline Company LLC, referred to in this report as Trailblazer, owns the 436-mile Trailblazer natural gas pipeline system. Our Trailblazer pipeline system originates at an interconnection with Wyoming Interstate Company Ltd.'s pipeline system near Rockport, Colorado and runs through southeastern Wyoming to a terminus near Beatrice, Nebraska where it interconnects with NGPL's and Northern Natural Gas Company's pipeline systems. NGPL manages, maintains and operates the Trailblazer system for us, for which it is reimbursed at cost. Trailblazer offers its customers firm and interruptible transportation, and in 2011, it transported an average of

approximately 717 million cubic feet per day of natural gas. All of the system's firm transport capacity is currently subscribed.

Kinder Morgan Louisiana Pipeline

Our subsidiary, Kinder Morgan Louisiana Pipeline LLC owns the Kinder Morgan Louisiana natural gas pipeline system. The pipeline system provides approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal located in Cameron Parish, Louisiana, and transports natural gas to various delivery points located in Cameron, Calcasieu, Jefferson Davis, Acadia and Evangeline parishes in Louisiana. The system capacity is fully supported by 20 year take-or-pay customer commitments with Chevron and Total that expire in 2029. The Kinder Morgan Louisiana pipeline system consists of two segments. The first is a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas that extends from the Sabine Pass terminal to a point of interconnection with an existing Columbia Gulf Transmission line in Evangeline Parish, Louisiana (an offshoot consists of approximately 2.3 miles of 24-inch diameter pipeline extending away from the 42-inch diameter line to the Florida Gas Transmission Company compressor station located in Acadia Parish, Louisiana). The second segment is a one-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that extends from the Sabine Pass terminal and connects to NGPL's natural gas pipeline. In 2011, our Kinder Morgan Louisiana pipeline system transported an average of approximately 21 million cubic feet per day of natural gas.

Midcontinent Express Pipeline LLC

We own a 50% interest in Midcontinent Express Pipeline LLC, the sole owner of the approximate 500-mile Midcontinent Express natural gas pipeline system. We also operate the Midcontinent Express pipeline system. Regency Midcontinent Express LLC owns the remaining 50% ownership interest. The Midcontinent Express pipeline system originates near Bennington, Oklahoma and extends eastward through Texas, Louisiana, and Mississippi, and terminates at an interconnection with the Transco Pipeline near Butler, Alabama. It interconnects with numerous major pipeline systems and provides an important infrastructure link in the pipeline system moving natural gas supply from newly developed areas in Oklahoma and Texas into the United States' eastern markets.

The pipeline system is comprised of approximately 30-miles of 30-inch diameter pipe, 275-miles of 42-inch diameter pipe and 197-miles of 36-inch diameter pipe. Midcontinent Express also has four compressor stations and one booster station totaling approximately 144,500 horsepower. It has two rate zones: (i) Zone 1 (which has a capacity of 1.8 billion cubic feet per day) beginning at Bennington and extending to an interconnect with Columbia Gulf Transmission near Delhi, in Madison Parish Louisiana; and (ii) Zone 2 (which has a capacity of 1.2 billion cubic feet per day) beginning at Delhi and terminating at an interconnection with Transco Pipeline near the town of Butler in Choctaw County, Alabama. Capacity on the Midcontinent Express system is 99% contracted under long-term firm service agreements that expire between 2012 and 2021. The majority of volume is contracted to producers moving supply from the Barnett shale and Oklahoma supply basins.

Fayetteville Express Pipeline LLC

We own a 50% interest in Fayetteville Express Pipeline LLC, the sole owner of the Fayetteville Express natural gas pipeline system. The 187-mile Fayetteville Express pipeline system originates in Conway County, Arkansas, continues eastward through White County, Arkansas, and terminates at an interconnect with Trunkline Gas Company's pipeline in Panola County, Mississippi. The system also interconnects with NGPL's pipeline in White County, Arkansas, Texas Gas Transmission's pipeline in Coahoma County, Mississippi, and ANR Pipeline Company's pipeline in Quitman County, Mississippi. On January 1, 2011, Fayetteville Express Pipeline LLC began firm contract pipeline transportation service to its customers. Capacity on the Fayetteville Express system is over 90% contracted under long-term firm service agreements.

Competition

The market for supply of natural gas is highly competitive, and new pipelines 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. These operations compete with interstate and intrastate pipelines, and their shippers, for attachments to new markets and supplies and for transportation, processing and treating services. We believe the principal elements of competition in our various markets are transportation rates, terms of service and flexibility and reliability of service. From time to time, other pipeline projects are proposed that would compete with our pipelines, and some proposed pipelines may deliver natural gas to markets we serve from new supply sources closer to those markets. 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 and fuel oils. 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.

CO₂

Our CO₂ segment consists of our subsidiary Kinder Morgan CO₂ Company, L.P. and its consolidated affiliates, collectively referred to in this report as KMCO₂. Our CO₂ business segment produces, transports, and markets carbon dioxide for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. KMCO₂'s carbon dioxide pipelines and related assets allow it to market a complete package of carbon dioxide supply, transportation and technical expertise to its customers. KMCO₂ also holds ownership interests in several oil-producing fields and owns a crude oil pipeline, all located in the Permian Basin region of West Texas.

Oil and Gas Producing Activities

Oil Producing Interests

KMCO₂ holds ownership interests in oil-producing fields located in the Permian Basin of West Texas, including: (i) an approximate 97% working interest in the SACROC unit; (ii) an approximate 50% working interest in the Yates unit; (iii) an approximate 21% net profits interest in the H.T. Boyd unit; (iv) an approximate 65% working interest in the Claytonville unit; (v) an approximate 99% working interest in the Katz Strawn unit; and (vi) lesser interests in the Sharon Ridge unit, the Reinecke unit and the MidCross unit.

The SACROC unit is one of the largest and oldest oil fields in the United States using carbon dioxide flooding technology. The field is comprised of approximately 56,000 acres located in the Permian Basin in Scurry County, Texas. KMCO₂ has expanded the development of the carbon dioxide project initiated by the previous owners and increased production and ultimate oil recovery over the last several years. In 2011, the average purchased carbon dioxide injection rate at SACROC was 154 million cubic feet per day. The average oil production rate for 2011 was approximately 28,600 barrels of oil per day (23,800 net barrels to KMCO₂ per day).

The Yates unit is also one of the largest oil fields ever discovered in the United States. The field is comprised of approximately 26,000 acres located about 90 miles south of Midland, Texas. KMCO₂'s plan over the last several years has been to maintain overall production levels and increase ultimate recovery from Yates by combining horizontal drilling with carbon dioxide injection to ensure a relatively steady production profile over the next several years. In 2011, the average purchased carbon dioxide injection rate at SACROC was 107 million cubic feet per day, and during 2011, the Yates unit produced approximately 21,700 barrels of oil per day (9,600 net barrels to KMCO₂ per day).

KMCO₂ also operates and owns an approximate 65% gross working interest in the Claytonville oil field unit and operates and owns an approximate 99% working interest in the Katz Strawn unit, both located in the Permian Basin area of West Texas. The Claytonville unit is located nearly 30 miles east of the SACROC unit, in Fisher County, Texas. The unit produced approximately 200 gross barrels of oil per day during 2011 (100 net barrels to KMCO₂ per day). During 2011, the Katz Strawn unit produced approximately 500 barrels of oil per day (400 net barrels to KMCO₂ per day). In 2011, the average purchased carbon dioxide injection rate at the Katz Strawn unit was 46 million cubic feet per day.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we owned interests as of December 31, 2011. The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. When used with respect to acres or wells, "gross" refers to the total acres or wells in which we have a working interest, and "net" refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells (a)		Service Wells (b)		Drilling Wells (c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,191	1,358	919	699	3	3
Natural Gas	5	2	-	-	-	-
Total Wells	<u>2,196</u>	<u>1,360</u>	<u>919</u>	<u>699</u>	<u>3</u>	<u>3</u>

- (a) Includes active wells and wells temporarily shut-in. As of December 31, 2011, we did not operate any productive wells with multiple completions.
- (b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of salt water into an underground formation; an injection well is a well drilled in a known oil field in order to inject liquids that enhance recovery.
- (c) Consists of development wells in the process of being drilled as of December 31, 2011. A development well is a well drilled in an already discovered oil field.

The following table reflects our net productive and dry wells that were completed in each of the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Productive			
Development	85	70	42
Exploratory.....	-	-	-
Dry			
Development	-	-	-
Exploratory.....	-	-	-
Total Wells	<u>85</u>	<u>70</u>	<u>42</u>

Note: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. A development well is a well drilled in an already discovered oil field.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2011:

	Gross	Net
Developed Acres	74,240	69,558
Undeveloped Acres	8,788	8,129
Total.....	<u>83,028</u>	<u>77,687</u>

Note: As of December 31, 2011, we have no material amount of acreage expiring in the next three years.

See Note 20 to our consolidated financial statements included elsewhere in this report for additional information with respect to operating statistics and supplemental information on our oil and gas producing activities.

Gas and Gasoline Plant Interests

KMCO₂ operates and owns an approximate 22% working interest plus an additional 28% net profits interest in the Snyder gasoline plant. It also operates and owns a 51% ownership interest in the Diamond M gas plant and a 100% ownership interest in the North Snyder plant, all of which are located in the Permian Basin of West Texas. The Snyder gasoline plant processes natural gas produced from the SACROC unit and neighboring carbon dioxide projects, specifically the Sharon Ridge and Cogdell units, all of which are located in the Permian Basin area of West Texas. The Diamond M and the North Snyder plants contract with the Snyder plant to process natural gas. Production of natural gas liquids at the Snyder gasoline plant during 2011 averaged approximately 16,600 gross barrels per day (8,300 net barrels to KMCO₂ per day excluding the value associated to KMCO₂'s 28% net profits interest).

Sales and Transportation Activities

Carbon Dioxide Reserves

KMCO₂ owns approximately 45% of, and operates, the McElmo Dome unit in Colorado, which contains more than 6.6 trillion cubic feet of recoverable carbon dioxide. It also owns approximately 87% of, and operates, the Doe Canyon Deep unit in Colorado, which contains more than 870 billion cubic feet of carbon dioxide. For both units combined, compression capacity exceeds 1.4 billion cubic feet per day of carbon dioxide and during 2011, the two units produced approximately 1.25 billion cubic feet per day of carbon dioxide.

KMCO₂ also owns approximately 11% of the Bravo Dome unit in New Mexico. The Bravo Dome unit contains more than 800 billion cubic feet of recoverable carbon dioxide and produced approximately 300 million cubic feet of carbon dioxide per day in 2011.

Our principal market for carbon dioxide is for injection into mature oil fields in the Permian Basin, where industry demand is expected to remain strong for the next several years.

Carbon Dioxide Pipelines

As a result of our 50% ownership interest in Cortez Pipeline Company, we own a 50% equity interest in and operate the approximate 500-mile Cortez pipeline. The pipeline carries carbon dioxide from the McElmo Dome and Doe Canyon source fields near Cortez, Colorado to the Denver City, Texas hub. The Cortez pipeline transports over 1.2 billion cubic feet of carbon dioxide per day. The tariffs charged by the Cortez pipeline are not regulated, but are based on a consent decree.

KMCO₂'s Central Basin pipeline consists of approximately 143 miles of mainline pipe and 177 miles of lateral supply lines located in the Permian Basin between Denver City, Texas and McCamey, Texas. The pipeline has an ultimate throughput capacity of 700 million cubic feet per day. At its origination point in Denver City, the Central Basin pipeline interconnects with all three major carbon dioxide supply pipelines from Colorado and New Mexico, namely the Cortez pipeline (operated by KMCO₂) and the Bravo and Sheep Mountain pipelines (operated by Oxy Permian). Central Basin's mainline terminates near McCamey, where it interconnects with the Canyon Reef Carriers pipeline and the Pecos pipeline. The tariffs charged by the Central Basin pipeline are not regulated.

KMCO₂'s Centerline carbon dioxide pipeline consists of approximately 113 miles of pipe located in the Permian Basin between Denver City, Texas and Snyder, Texas. The pipeline has a capacity of 300 million cubic feet per day. The tariffs charged by the Centerline pipeline are not regulated.

KMCO₂'s Eastern Shelf carbon dioxide pipeline, which consists of approximately 91 miles of pipe located in the Permian Basin, begins near Snyder, Texas and ends west of Knox City, Texas. The pipeline has a current capacity of 70 million cubic feet per day, expandable to 200 million cubic feet per day in the future. The Eastern Shelf Pipeline system is currently flowing 56 million cubic feet per day. The tariffs charged on the Eastern Shelf pipeline are not regulated.

KMCO₂ also owns a 13% undivided interest in the 218-mile, Bravo pipeline, which delivers carbon dioxide from the Bravo Dome source field in northeast New Mexico to the Denver City hub and has a capacity of more than 350 million cubic feet per day. Tariffs on the Bravo pipeline are not regulated. Occidental Petroleum (81%) and XTO Energy (6%) hold the remaining ownership interests in the Bravo pipeline.

In addition, KMCO₂ owns approximately 98% of the Canyon Reef Carriers pipeline and approximately 69% of the Pecos pipeline. The Canyon Reef Carriers pipeline extends 139 miles from McCamey, Texas, to the SACROC unit in the Permian Basin. The pipeline has a capacity of approximately 270 million cubic feet per day and makes deliveries to the SACROC, Sharon Ridge, Cogdell and Reinecke units. The Pecos pipeline is a 25-mile pipeline that runs from McCamey to Iraan, Texas. It has a capacity of approximately 120 million cubic feet per day and makes deliveries to the Yates unit. The tariffs charged on the Canyon Reef Carriers and Pecos pipelines are not regulated.

The principal market for transportation on our carbon dioxide pipelines is to customers, including ourselves, using carbon dioxide for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain strong for the next several years.

Crude Oil Pipeline

KMCO₂ owns the Kinder Morgan Wink Pipeline, a 450-mile Texas intrastate crude oil pipeline system consisting of three mainline sections, two gathering systems and numerous truck delivery stations. The pipeline allows KMCO₂ to better manage crude oil deliveries from its oil field interests in West Texas. KMCO₂ has entered into a long-term throughput agreement with Western Refining Company, L.P. to transport crude oil into Western's 120,000 barrel per day refinery located in El Paso, Texas. The throughput agreement expires in 2034. The 20-inch diameter pipeline segment that runs from Wink to El Paso, Texas has a total capacity of 130,000 barrels of crude oil per day, and it transported approximately 112,000 barrels of oil per day in 2011. The Kinder Morgan Wink Pipeline is regulated by both the FERC and the Texas Railroad Commission.

Competition

Our primary competitors for the sale of carbon dioxide include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain carbon dioxide reserves, and Petro-Source Carbon Company, which gathers waste carbon dioxide from natural gas production in the Val Verde Basin of West Texas. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other carbon dioxide pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of carbon dioxide to the Denver City, Texas market area.

Terminals

Our Terminals segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately 115 owned or operated liquids and bulk terminal facilities and approximately 35 rail transloading and materials handling facilities. Our terminals are located throughout the United States and in portions of Canada. We believe the location of our facilities and our ability to provide flexibility to customers helps keep customers at our terminals and provides us opportunities for expansion. We often classify our terminal operations based on their handling of either liquids or bulk material products.

Liquids Terminals

Our liquids terminals operations primarily store refined petroleum products, petrochemicals, ethanol, industrial chemicals and vegetable oil products in aboveground storage tanks and transfer products to and from pipelines, vessels, tank trucks, tank barges, and tank railcars. Combined, our approximately 25 liquids terminals facilities possess liquids storage capacity of approximately 60.2 million barrels, and in 2011, these terminals handled approximately 616 million barrels of liquids products, including petroleum products, ethanol and chemicals.

Bulk Terminals

Our bulk terminal operations primarily involve dry-bulk material handling services. We also provide conveyor manufacturing and installation, engineering and design services, and in-plant services covering material handling, conveying, maintenance and repair, truck-railcar-marine transloading, railcar switching and miscellaneous marine services. We own or operate approximately 90 dry-bulk terminals in the United States and Canada, and combined, our dry-bulk and material transloading facilities (described below) handled approximately 100.6 million tons of coal, petroleum coke, fertilizers, steel, ores and other dry-bulk materials in 2011.

Materials Services (rail transloading)

Our materials services operations include rail or truck transloading shipments from one medium of transportation to another conducted at approximately 35 owned and non-owned facilities. The Burlington Northern Santa Fe, CSX, Norfolk Southern, Union Pacific, Kansas City Southern and A&W railroads provide rail service for these terminal facilities. Approximately 50% of the products handled are liquids, including an entire spectrum of liquid chemicals, and the rest are dry-bulk products. Many of the facilities are equipped for bi-modal operation (rail-to-truck, and truck-to-rail) or connect via pipeline to storage facilities. Several facilities provide railcar storage services. We also design and build transloading facilities, perform inventory management services, and provide value-added services such as blending, heating and sparging.

Competition

We are one of the largest independent operators of liquids terminals in the United States, 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 and pipeline 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 terminal services. In some locations, our competitors are smaller, independent operators with lower cost structures. Our rail transloading (material services) operations compete with a variety of single- or multi-site transload, warehouse and terminal operators across the United States. Our ethanol rail transload operations compete with a variety of ethanol handling terminal sites across the United States, many offering waterborne service, truck loading, and unit train capability serviced by Class 1 rail carriers.

Kinder Morgan Canada

Our Kinder Morgan Canada business segment includes our Trans Mountain pipeline system, our ownership of a one-third interest in the Express pipeline system, and our 25-mile Jet Fuel pipeline system. The weighted average remaining life of the shipping contracts on these pipeline systems was approximately two years as of December 31, 2011.

Trans Mountain Pipeline System

Our Trans Mountain pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum products to destinations in the interior and on the west coast of British Columbia. Trans Mountain's pipeline is 715 miles in length. We also own a connecting pipeline that delivers crude oil to refineries in the state of Washington. The capacity of the line at Edmonton ranges from 300,000 barrels per day when heavy crude represents 20% of the total throughput (which is a historically normal heavy crude percentage), to 400,000 barrels per day with no heavy crude. Trans Mountain is the sole pipeline carrying crude oil and refined petroleum products from Alberta to the west coast. We believe these facilities provide us the opportunity to consider capacity expansions to the west coast, either in stages or as one project, as the market for offshore exports continues to develop.

In 2011, Trans Mountain delivered an average of 274,000 barrels per day. The crude oil and refined petroleum products transported through Trans Mountain's pipeline system originates in Alberta and British Columbia. The refined and partially refined petroleum products transported to Kamloops, British Columbia and Vancouver originates from oil refineries located in Edmonton. Petroleum products delivered through Trans Mountain's pipeline system are used in markets in British Columbia, Washington State and elsewhere offshore.

Trans Mountain also operates a 5.3 mile spur line from its Sumas Pump Station to the U.S. – Canada international border where it connects with our approximate 63-mile, 16-inch to 20-inch diameter Puget Sound pipeline system. The Puget Sound pipeline system in the state of Washington has a sustainable throughput capacity of approximately 135,000 barrels per day when heavy crude represents approximately 25% of throughput, and it connects to four refineries located in northwestern Washington State. The volumes of crude oil shipped to the state of Washington fluctuate in response to the price levels of Canadian crude oil in relation to crude oil produced in Alaska and other offshore sources.

In January 2012, Trans Mountain completed negotiations with the Canadian Association of Petroleum Producers for a new negotiated toll settlement effective for the period beginning January 1, 2012 and ending December 31, 2012. Trans Mountain anticipates National Energy Board approval in the second quarter of 2012.

Express and Jet Fuel Pipeline Systems

We own a one-third ownership interest in the Express pipeline system, and a subordinated debenture issued by Express US Holdings LP, the partnership that maintains ownership of the U.S. portion of the Express pipeline system. We operate the Express pipeline system and account for our one-third investment under the equity method of accounting. The Express pipeline system is a batch-mode, common-carrier, crude oil pipeline system comprised of the Express Pipeline and the Platte Pipeline, collectively referred to in this report as the Express pipeline system. The approximate 1,700-mile integrated oil transportation pipeline connects Canadian and United States producers to refineries located in the U.S. Rocky Mountain and Midwest regions.

The Express Pipeline is a 780-mile, 24-inch diameter pipeline that begins at the crude oil pipeline terminal at Hardisty, Alberta and terminates at the Casper, Wyoming facilities of the Platte Pipeline. The Express Pipeline has a design capacity of 280,000 barrels per day. Receipts at Hardisty averaged 175,000 barrels per day in 2011.

The Platte Pipeline is a 926-mile, 20-inch diameter pipeline that runs from the crude oil pipeline terminal at Casper, Wyoming to refineries and interconnecting pipelines in the Wood River, Illinois area. The Platte Pipeline has a current capacity of approximately 150,000 barrels per day downstream of Casper, Wyoming and approximately 140,000 barrels per day downstream of Guernsey, Wyoming. Platte deliveries averaged 148,000 barrels per day in 2011.

We also own and operate the approximate 25-mile aviation fuel pipeline that serves the Vancouver International Airport, located in Vancouver, British Columbia, Canada. The turbine fuel pipeline is referred to in this report as our Jet Fuel pipeline system. In addition to its receiving and storage facilities located at the Westridge Marine terminal, located in Port Metro Vancouver, the Jet Fuel pipeline system's operations include a terminal at the Vancouver airport that consists of five jet fuel storage tanks with an overall capacity of 15,000 barrels.

Competition

Trans Mountain and the Express pipeline system are each one of several pipeline alternatives for western Canadian crude oil and refined petroleum production, and each competes against other pipeline providers.

Major Customers

Our total operating revenues are derived from a wide customer base. For each of the years ended December 31, 2011, 2010 and 2009, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas, and, to a far lesser extent, our CO₂ business segment also sells natural gas. Combined, total revenues from the sales of natural gas from our Natural Gas Pipelines and CO₂ business segments in 2011, 2010 and 2009 accounted for 40.6%, 44.8% and 44.8%, 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. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

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

Some of our U.S. refined petroleum products and crude oil 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 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.

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act 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 16 to our consolidated financial statements included elsewhere in this report.

Petroleum products 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 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 crude oil and refined petroleum products pipeline systems is under the regulatory jurisdiction of Canada's National Energy Board, referred to in this report as the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service.

Trans Mountain Pipeline. Our subsidiary Trans Mountain Pipeline, L.P. previously had a one-year toll settlement with shippers that expired on December 31, 2011. In January 2012, Trans Mountain Pipeline completed negotiations with the Canadian Association of Petroleum Producers for a new negotiated toll settlement for our Trans Mountain Pipeline to be effective for 2012. Trans Mountain anticipates approval from the NEB in the second quarter of 2012. The toll charged for the portion of Trans Mountain's pipeline system located in the United States falls under the jurisdiction of the FERC. See "—Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation – U.S. Operations."

Express Pipeline. The Canadian segment of the Express Pipeline is regulated by the NEB as a Group 2 pipeline, which results in rates and terms of service being regulated on a complaint basis only. Express committed contract rates are subject to a 2% inflation adjustment April 1 of each year. The U.S. segment of the Express Pipeline and the Platte Pipeline are regulated by the FERC. See "—Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation – U.S. Operations." Additionally, movements on the Platte Pipeline within the state of Wyoming are regulated by the Wyoming Public Service Commission, which regulates the tariffs and terms of service of public utilities that operate in the state of Wyoming. The Wyoming Public Service Commission standards applicable to rates are similar to those of the FERC and the NEB.

Interstate Natural Gas Transportation and Storage Regulation

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 to meet competition, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates offered within the range of tariff maximums and minimums, the pipeline is permitted to offer negotiated rates where the pipeline and shippers want rate certainty, 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 a fixed rate during the term of the transportation agreement, regardless of changes to the posted tariff rates. There are a variety of rates that different shippers may pay, and while rates may vary by shipper and circumstance, the terms and conditions of pipeline transportation and storage services are not generally negotiable.

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, through the mid-1990's, the FERC initiated a number of regulatory changes intended to create a more competitive 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; and
- 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 the natural gas commodity, transportation and storage).

The FERC also promulgates certain standards of conduct that apply uniformly to interstate natural gas pipelines and public utilities. In light of the changing structure of the energy industry, these standards of conduct govern employee relationships—using a functional approach—to ensure that natural gas transmission is provided on a nondiscriminatory

basis. Pursuant to the FERC's standards of conduct, a natural gas transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. Additionally, no-conduit provisions prohibit a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit.

The FERC standards of conduct address and clarify multiple issues, including (i) the definition of transmission function and transmission function employees; (ii) the definition of marketing function and marketing function employees; (iii) the definition of transmission function information; (iv) independent functioning; (v) transparency; and (vi) the interaction of FERC standards with the North American Energy Standards Board business practice standards. Rules also require that a transmission provider provide annual training on the standards of conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information.

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.

California Public Utilities Commission Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the California Public Utilities Commission, referred to in this report as 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 our 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 our intrastate rates. Certain of our Pacific operations' pipeline rates have been, and continue to be, subject to complaints with the CPUC, as is more fully described in Note 16 to our consolidated financial statements included elsewhere in this report.

Texas Railroad Commission Rate Regulation

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

Safety Regulation

Our interstate pipelines are subject to regulation by the United States Department of Transportation, referred to in this report as the U.S. DOT, and our intrastate pipelines and other operations are subject to comparable state regulations with respect to their design, installation, testing, construction, operation, replacement and management. Comparable regulation exists in some states in which we conduct pipeline operations. In addition, our truck and terminal loading facilities are subject to U.S. DOT regulations dealing with the transportation of hazardous materials by motor vehicles and railcars.

On September 15, 2010, the secretary of the U.S. DOT sent to the U.S. Congress proposed legislation to provide stronger oversight of the nation's pipelines and to increase the penalties for violations of pipeline safety rules. The proposed legislation entitled "Strengthening Pipeline Safety and Enforcement Act of 2010," would, among other things, increase the maximum fine for the most serious violations from \$1 million to \$2.5 million, provide additional resources for the enforcement program, require a review of whether safety requirements for "high consequence areas" should be applied instead to entire pipelines, eliminate exemptions and ensure standards are in place for bio-fuel and carbon dioxide pipelines.

The Pipeline Safety Improvement Act of 2002 provides guidelines in the areas of testing, education, training and communication. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity tests on natural gas transmission pipelines that exist in high population density areas that are designated as "high consequence areas." Testing consists of hydrostatic testing, internal magnetic flux or ultrasonic testing, or direct assessment of the piping. In

addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. A similar integrity management rule exists for refined petroleum products pipelines.

We are also subject to the requirements of the Federal Occupational Safety and Health Act and other comparable federal and state statutes that address employee health and safety. In general, we expect to 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 accurately estimated at this time.

State and Local Regulation

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

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 United States 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 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 U.S. generally accepted accounting principles, 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 probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency, referred to in this report as the U.S. 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 multiparty 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 \$74.7 million as of December 31, 2011. Our reserve estimates range in value from approximately \$74.7 million to approximately \$129.7 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 16 to our consolidated financial statements included elsewhere in this report.

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 statutes. From time to time, the U.S. EPA and state and Canadian 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, 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 Comprehensive Environmental Response, Compensation and Liability Act, also known as 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 U.S. EPA and, in some cases, third parties to take actions in response to threats to the 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. We believe that the operations of our pipelines, storage facilities and terminals are in substantial compliance with such statutes. The U.S. EPA adopted new regulations under the Clean Air Act that took effect in early 2011 and that establish requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. These regulations contain lengthy, complex provisions that may result in the imposition over the next several years of certain pollution control requirements with respect to air emissions from the operations of our pipelines, treating and processing facilities, storage facilities, terminals and wells. Depending on the nature of those requirements and any additional requirements that may be imposed by state and local regulatory authorities, we may be required to incur capital and operating expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals and addressing other air emission-related issues. At this time, we are unable to fully estimate the effect on earnings or operations or the amount and timing of such required capital expenditures; however, we do not believe that we will be materially adversely affected by any such requirements.

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 state waters or waters of the United States. 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 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.

Climate Change

Studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. It is not possible at this time to predict what action, if any, the U.S. Congress may take in regard to greenhouse gas legislation.

As discussed above under "—Clean Air Act," the U.S. EPA adopted new regulations under the Clean Air Act that took effect in early 2011 and that establish requirements for the monitoring, reporting, and control of greenhouse gas emissions from stationary sources. These regulations include the reporting of greenhouse gas emissions in the United States from specified large greenhouse gas emission sources, fractionated natural gas liquids, and the production of naturally occurring carbon dioxide, like the McElmo Dome carbon dioxide field, even when such production is not emitted to the atmosphere.

Because our operations, including our compressor stations and gas processing plants in our Natural Gas Pipelines segment, emit various types of greenhouse gases, primarily methane and carbon dioxide, such legislation or regulation could increase our costs related to operating and maintaining our facilities and require us to install new emission controls on our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We are not able at this time to estimate such increased costs; however, they could be significant. While we may be able to include some or all of such increased costs in the rates charged by our natural gas pipelines, such recovery of costs is uncertain in all cases and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or other regulations. Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Some climatic 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. To the extent these phenomena occur, they could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone regions. However, the timing and location of these climate change impacts is not known with any certainty and, in any event, these impacts are expected to manifest themselves over a long time horizon. Thus, we are not in a position to say whether the physical impacts of climate change pose a material risk to our business, financial position, results of operations or cash flows.

Because natural gas emits less greenhouse gas emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or U.S. EPA regulatory initiatives could stimulate demand for natural gas by increasing the relative cost of fuels such as coal and oil. In addition, we anticipate that greenhouse gas regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO₂ business segment. However, these 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 the magnitude and direction of these impacts cannot now be predicted, greenhouse gas regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

In Section 550 of the Homeland Security Appropriations Act of 2007, the U.S. Congress gave the Department of Homeland Security, referred to in this report as the DHS, regulatory authority over security at certain high-risk chemical facilities. Pursuant to its congressional mandate, on April 9, 2007, the DHS 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

KMGP Services Company, Inc., KMI and Kinder Morgan Canada Inc. employ all persons necessary for the operation of our business. Generally, we reimburse these entities for the services of their employees. As of December 31, 2011, KMGP Services Company, Inc., KMI and Kinder Morgan Canada Inc. had, in the aggregate, 8,120 full-time employees. Approximately 833 full-time hourly personnel at certain terminals and pipelines are represented by labor unions under collective bargaining agreements that expire between 2012 and 2016. KMGP Services Company, Inc., KMI and Kinder Morgan Canada Inc. each consider relations with their employees to be good. For more information on our related party transactions, see Note 11 to our consolidated financial statements included elsewhere in this report.

Properties

We believe that we have generally 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 the right to construct and operate the pipelines on other people's land for a period of time. 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 in fee.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 15 to our consolidated financial statements included elsewhere in this report.

(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 Securities and Exchange Commission. 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 Securities and Exchange Commission.

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 position, results of operations or cash flows. There are also risks associated with being an owner of common units in a partnership that are different than being an owner of common stock in a corporation. Investors in our common units should be aware that the realization of any of those risks could result in a decline in the trading price of our common units, and they might lose all or part of their investment.

Risks Related to Our Business

New regulations, rulemaking and oversight, as well as changes in regulations, by regulatory agencies having jurisdiction over our operations could adversely impact our income and operations.

Our pipelines and storage facilities are subject to regulation and oversight by federal, state and local regulatory authorities, such as the FERC, the CPUC and the NEB. Regulatory actions taken by these agencies have the potential to adversely affect our profitability. Regulation affects almost every part of our business and extends to such matters as (i) rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (ii) the types of services we may offer to our customers; (iii) the contracts for service entered into with our customers; (iv) the certification and construction of new facilities; (v) the integrity, safety and security of facilities and operations; (vi) the acquisition of other businesses; (vii) the acquisition, extension, disposition or abandonment of services or facilities; (viii) reporting and information posting requirements; (ix) the maintenance of accounts and records; and (x) relationships with affiliated companies involved in various aspects of the natural gas and energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of such regulatory authorities, we could be subject to substantial penalties and fines. Furthermore, new laws or regulations sometimes arise from unexpected sources. For example, the Department of Homeland Security Appropriation Act of 2007 required the Department of Homeland Security to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." New laws or regulations, or different interpretations of existing laws or regulations, including unexpected policy changes,

applicable to us or our assets could have a material adverse impact on our business, financial condition and results of operations. For more information, see Items 1 and 2 “Business and Properties—(c) Narrative Description of Business—Regulation.”

The FERC or the CPUC may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, the CPUC, or our customers could file complaints challenging the tariff rates charged by our pipelines, and a successful complaint 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 such costs increase in an amount greater than what we are permitted by the FERC or the CPUC to recover in our rates, or to the extent that there is a lag before the pipeline can file and obtain rate increases, such events can have a negative impact upon 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 FERC and the CPUC that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates on our West Coast Products Pipeline systems. Further, the FERC has initiated investigations to determine whether some interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 16 to our consolidated financial statements included elsewhere in this report, to the rates we charge on our pipelines. Any successful challenge could materially adversely affect our future earnings, cash flows and financial condition.

Energy 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 natural gas transmission and storage activities and refined petroleum products and carbon dioxide transportation activities—such as leaks, explosions and mechanical problems—that could result in substantial financial losses. In addition, these risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution and impairment of operations, any of which also could result in substantial financial losses. 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 could be greater. Incidents that cause an interruption of service, such as when unrelated third party construction damages a pipeline or a newly completed expansion experiences a weld failure, may negatively impact our revenues and earnings while the affected asset is temporarily out of service. In addition, if losses in excess of our insurance coverage were to occur, they could have a material adverse effect on our business, financial condition and results of operations.

Increased regulatory requirements relating to the integrity of our pipelines will require us to spend additional money to comply with these requirements.

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the U.S. DOT and pipeline companies in the areas of testing, education, training and communication. The U.S. DOT issued final rules (effective February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in what the rules refer to as “High Consequence Areas.” The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of the costs to comply with the rules are associated with pipeline integrity testing and the repairs found to be necessary. Changes such as advances of 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 the costs to perform integrity testing and repairs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. 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.

We may face competition from competing pipelines and other forms of transportation into the areas we serve as well as with respect to the supply for our pipeline systems.

Any current or future pipeline system or other form of transportation that delivers crude oil, petroleum products or natural gas 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. To the extent that an excess of supply into these areas is created and persists, our ability to recontract for expiring transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We also could experience competition for the supply of petroleum products or natural gas from both existing and proposed pipeline systems. Several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us.

Cost overruns and delays on our expansion and new build projects could adversely affect our business.

We recently completed several major expansion and new build projects, including the joint venture projects Rockies Express Pipeline, Midcontinent Express Pipeline and Fayetteville Express Pipeline. We also are conducting and conduct from time to time alone or with others what are referred to as “open seasons” to evaluate the potential customer interest for new construction projects. A variety of factors outside of our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as performance by third-party contractors, has resulted in, and may continue to result in, increased costs or delays in construction. Significant cost overruns or delays in completing a project could have a material adverse effect on our return on investment, results of operations and cash flows.

We must either obtain the right from landowners or exercise the power of eminent domain in order to use most of the land on which our pipelines are constructed, and we are subject to the possibility of increased costs to retain necessary land use.

We obtain the right to construct and operate pipelines on other owners’ land for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be affected negatively. In addition, we are subject to the possibility of increased costs under our rental agreements with landowners, primarily through rental increases and renewals of expired agreements.

Whether we have the power of eminent domain for our pipelines, other than interstate natural gas pipelines, varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas or carbon dioxide—and the laws of the particular state. Our interstate natural gas pipelines have federal eminent domain authority. In either case, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

Our acquisition strategy and expansion programs require access to new capital. Tightened capital markets or more expensive capital would impair our ability to grow.

Consistent with the terms of our partnership agreement, we have distributed most of the cash generated by our operations. As a result, we have relied on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisition and growth capital expenditures. However, to the extent we are unable to continue to finance growth externally, our cash distribution policy will significantly impair our ability to grow. We may need new capital to finance these activities. Limitations on our access to capital will impair our ability to execute this strategy.

Our growth strategy may cause difficulties integrating and constructing new operations, and we may not be able to achieve the expected benefits from any future acquisitions.

Part of our business strategy includes acquiring additional businesses, expanding existing assets and constructing new facilities. If we do not successfully integrate acquisitions, expansions or newly constructed facilities, we may not realize anticipated operating advantages and cost savings. The integration of companies that have previously operated separately involves a number of risks, including (i) demands on management related to the increase in our size after an acquisition, expansion or completed construction project; (ii) the diversion of management’s attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems; (iv) difficulties in the assimilation and retention of necessary employees; and (v) potential adverse effects on operating results.

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, expansion or construction project will depend upon our ability to manage those operations and to eliminate redundant and excess costs. 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.

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 or analogous state laws for the remediation of contaminated areas. 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 also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could influence 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 or our 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 for 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 level of earnings and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While 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 United States 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.

In addition, our oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. 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 in restricted areas, 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.

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. 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."

Climate change regulation at the federal, state, provincial or regional levels could result in increased operating and capital costs for us.

Methane, a primary component of natural gas, and carbon dioxide, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. EPA began regulating the greenhouse gas emissions of certain stationary sources on January 2, 2011, and issued a final rule requiring the reporting of greenhouse gas emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large greenhouse gas emission sources, fractionated natural gas liquids, and the production of naturally occurring carbon dioxide, like our McElmo Dome carbon dioxide field, even when such production is not emitted to the atmosphere.

Because our operations, including our compressor stations and natural gas processing plants in our Natural Gas Pipelines segment, emit various types of greenhouse gases, primarily methane and carbon dioxide, such regulation could increase our costs related to operating and maintaining our facilities and require us to install new emission controls on our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We are not able at this time to estimate such increased costs; however, they 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 and the provisions of any final legislation or other regulations. Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows. For more information about climate change regulation, see Items 1 and 2 “Business and Properties—(c) Narrative Description of Business—Environmental Matters—Climate Change.”

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, which could adversely impact our revenues by decreasing the volumes of natural gas transported on our or our joint ventures’ natural gas pipelines.

The natural gas industry is increasingly relying on natural gas supplies from unconventional sources, such as shale, tight sands and coal bed methane. Natural gas extracted 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. Recently, 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 natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas transported on our or our joint ventures’ natural gas pipelines, several of which gather gas from areas in which the use of hydraulic fracturing is prevalent.

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

As of December 31, 2011, we had \$12.8 billion of consolidated debt (excluding the value of interest rate swap agreements). This level of debt 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) limiting our ability to use operating cash flow in other areas of our business or to pay distributions because we must dedicate a substantial portion of these funds to make payments on our debt; (iii) placing us at a competitive disadvantage compared to competitors with less debt; and (iv) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our debt 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 operating results are not sufficient to service our indebtedness, or any future indebtedness that we incur, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. 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 8 to our consolidated financial statements included elsewhere in this report.

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

As of December 31, 2011, approximately \$6.0 billion (47%) of our total \$12.8 billion consolidated debt (excluding the value of interest rate swap agreements) was subject to variable interest rates, either as short-term or long-term debt of 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 this debt would increase and our earnings 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.”

Current or future distressed financial conditions of our customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations, financial condition, and cash flows.

Terrorist attacks, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other energy assets might be specific targets of terrorist organizations. These potential targets might include our pipeline systems or storage facilities. Our operations could become subject to increased governmental scrutiny that would require increased security measures. There is no assurance that adequate 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.

Future business development of our pipelines is dependent on the supply of and demand for the commodities transported by our pipelines.

Our pipelines depend on production of natural gas, oil and other products in the areas served by our pipelines. Without reserve additions, production will decline over time as reserves are depleted and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as in the Alberta oil sands. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our gas plants and pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at a level that encourages 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 a decline in crude oil or natural gas prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from oil and natural gas producing areas. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil and natural gas. Each of these factors impact our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

Throughput on our crude oil, natural gas and refined petroleum products pipelines also may decline as a result of changes in business conditions. Over the long term, business will depend, in part, on the level of demand for oil, natural gas and refined petroleum products in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand.

The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas, crude oil and refined petroleum products, increase our costs and may have a material adverse effect on our results of operations and financial condition. 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 demand for natural gas, crude oil and refined petroleum products.

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 and revenues of the oil and gas producing assets within our CO₂ business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

The development of 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.

The volatility of natural gas and oil prices could have a material adverse effect on our business.

The revenues, profitability and future growth of our CO₂ business segment and the carrying value of its oil, natural gas liquids and natural gas properties depend to a large degree on prevailing oil and gas prices. For 2012, we estimate that every \$1 change in the average West Texas Intermediate crude oil price per barrel would impact our CO₂ segment's cash flows by approximately \$5.8 million. Prices for oil, natural gas liquids and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil, natural gas liquids 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 United States; (ii) the condition of the United States economy; (iii) the activities of the Organization of Petroleum Exporting Countries; (iv) governmental regulation; (v) political stability in the Middle East and elsewhere; (vi) the foreign supply of and demand for oil and natural gas; (vii) the price of foreign imports; and (viii) the availability of alternative fuel sources.

A sharp decline in the price of oil, natural gas liquids or natural gas would result in a commensurate reduction in our revenues, income and cash flows from the production of oil, natural gas liquids, and natural gas and could have a material adverse effect on the carrying value of our proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our production and would operate at a loss. In recent decades, there have been periods of both worldwide 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 excess or short supply of crude oil or natural gas has placed pressures on prices and has 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."

Our use of hedging arrangements could result in financial losses or reduce our income.

We engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil and natural gas. 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 oil and natural gas.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those statements. In addition, it is not always possible for us to engage in hedging transactions that completely mitigate our exposure to commodity prices. 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 13 to our consolidated financial statements included elsewhere in this report.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, referred to as the CFTC, and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The act also requires the CFTC to institute broad new position limits for futures and options traded on regulated exchanges. As the law favors exchange trading and clearing, the Dodd-Frank Act also may require us to move certain derivatives transactions to exchanges where no trade credit is provided and also comply with margin requirements in connection with our derivatives activities that are not exchange traded, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act also requires many counterparties to our derivatives instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with the capital requirements, which could result in increased costs to counterparties such as us. The Dodd-Frank Act and any new regulations could (i) significantly increase the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduce the availability of derivatives to protect against risks we encounter; and (iii) reduce the liquidity of energy related derivatives.

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. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

Our Kinder Morgan Canada segment is subject to U.S. dollar/Canadian dollar exchange rate fluctuations.

We are a U.S. dollar reporting company. As a result of the operations of our Kinder Morgan Canada business segment, a portion of our consolidated assets, liabilities, revenues and expenses are denominated in Canadian dollars. Fluctuations in the exchange rate between United States 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 partners’ capital under applicable accounting rules.

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

Economic conditions worldwide have from time to time contributed to slowdowns in several industries, including the oil and gas industry, the steel industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions also may be affected by uncertain or changing economic conditions within that region, such as the challenges that are currently affecting economic conditions in the United States and Canada. Volatility in commodity prices might have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. In addition, decreases in the prices of crude oil and natural gas liquids will have a negative impact on the results of our CO₂ business segment. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the United States or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

Hurricanes, earthquakes and other natural disasters 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 areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage or destroy our pipelines, terminals and other assets and disrupt the supply of the products we transport through our pipelines. Natural disasters 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.

Risks Related to Our Common Units

The interests of KMI may differ from our interests and the interests of our unitholders.

KMI indirectly owns all of the common stock of our general partner and elects all of its directors. Our general partner owns all of KMR's voting shares and elects all of its directors. Furthermore, some of KMR's directors and officers are also directors and officers of KMI and our general partner and have fiduciary duties to manage the businesses of KMI in a manner that may not be in the best interests of our unitholders. KMI has a number of interests that differ from the interests of our unitholders. As a result, there is a risk that important business decisions will not be made in the best interests of our unitholders.

Common unitholders have limited voting rights and limited control.

Holders of common units have only limited voting rights on matters affecting us. Our general partner manages partnership activities. Under a delegation of control agreement, our general partner has delegated the management and control of our and our subsidiaries' business and affairs to KMR. Holders of common units have no right to elect the general partner on an annual or other ongoing basis. If the general partner withdraws, however, its successor may be elected by the holders of a majority of the outstanding common units (excluding units owned by the departing general partner and its affiliates).

The limited partners may remove the general partner only if (i) the holders of at least 66 2/3% of the outstanding common units, excluding common units owned by the departing general partner and its affiliates, vote to remove the general partner; (ii) a successor general partner is approved by at least 66 2/3% of the outstanding common units, excluding common units owned by the departing general partner and its affiliates; and (iii) we receive an opinion of counsel opining that the removal would not result in the loss of limited liability to any limited partner, or the limited partner of an operating partnership, or cause us or the operating partnership to be taxed other than as a partnership for federal income tax purposes.

A person or group owning 20% or more of the common units cannot vote.

Any common units held by a person or group that owns 20% or more of the common units cannot be voted. This limitation does not apply to the general partner and its affiliates. This provision may (i) discourage a person or group from attempting to remove the general partner or otherwise change management; and (ii) reduce the price at which the common units will trade under certain circumstances. For example, a third party will probably not attempt to take over our management by making a tender offer for the common units at a price above their trading market price without removing the general partner and substituting an affiliate of its own.

The general partner's liability to us and our unitholders may be limited.

Our partnership agreement contains language limiting the liability of the general partner to us or the holders of common units. For example, our partnership agreement provides that (i) the general partner does not breach any duty to us or the holders of common units by borrowing funds or approving any borrowing (the general partner is protected even if the purpose or effect of the borrowing is to increase incentive distributions to the general partner); (ii) the general partner does not breach any duty to us or the holders of common units by taking any actions consistent with the standards of reasonable discretion outlined in the definitions of available cash and cash from operations contained in our partnership agreement; and (iii) the general partner does not breach any standard of care or duty by resolving conflicts of interest unless the general partner acts in bad faith.

Unitholders may have liability to repay distributions.

Unitholders will not be liable for assessments in addition to their initial capital investment in the common units. Under certain circumstances, however, holders of common units may have to repay us amounts wrongfully returned or

distributed to them. Under Delaware law, we may not make a distribution to unitholders if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of such a distribution, a limited partner who receives the distribution and knew at the time of the distribution that the distribution violated Delaware law will be liable to the limited partnership for the distribution amount. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to the assignee at the time the assignee became a limited partner if the liabilities could not be determined from the partnership agreement.

Unitholders may be liable if we have not complied with state partnership law.

We conduct our business in a number of states. In some of those states the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. The unitholders might be held liable for the partnership's obligations as if they were a general partner if (i) a court or government agency determined that we were conducting business in the state but had not complied with the state's partnership statute; or (ii) unitholders' rights to act together to remove or replace the general partner or take other actions under our partnership agreement constitute "control" of our business.

The general partner may buy out minority unitholders if it owns 80% of the units.

If at any time the general partner and its affiliates own 80% or more of the issued and outstanding common units, the general partner will have the right to purchase all, and only all, of the remaining common units. Because of this right, a unitholder could have to sell its common units at a time or price that may be undesirable. The purchase price for such a purchase will be the greater of (i) the 20-day average trading price for the common units as of the date five days prior to the date the notice of purchase is mailed; or (ii) the highest purchase price paid by the general partner or its affiliates to acquire common units during the prior 90 days. The general partner can assign this right to its affiliates or to us.

We may sell additional limited partner interests, diluting existing interests of unitholders.

Our partnership agreement allows the general partner to cause us to issue additional common units and other equity securities. When we issue additional equity securities, including additional i-units to KMR when it issues additional shares, unitholders' proportionate partnership interest in us will decrease. Such an issuance could negatively affect the amount of cash distributed to unitholders and the market price of common units. Issuance of additional common units will also diminish the relative voting strength of the previously outstanding common units. Our partnership agreement does not limit the total number of common units or other equity securities we may issue.

The general partner can protect itself against dilution.

Whenever we issue equity securities to any person other than the general partner and its affiliates, the general partner has the right to purchase additional limited partnership interests on the same terms. This allows the general partner to maintain its proportionate partnership interest in us. No other unitholder has a similar right. Therefore, only the general partner may protect itself against dilution caused by issuance of additional equity securities.

Our partnership agreement and the KMR limited liability company agreement restrict or eliminate a number of the fiduciary duties that would otherwise be owed by our general partner and/or its delegate to our unitholders.

Modifications of state law standards of fiduciary duties may significantly limit the ability of our unitholders to successfully challenge the actions of our general partner in the event of a breach of fiduciary duties. These state law standards include the duties of care and loyalty. The duty of loyalty, in the absence of a provision in the limited partnership agreement to the contrary, would generally prohibit our general partner from taking any action or engaging in any transaction as to which it has a conflict of interest. Our limited partnership agreement contains provisions that prohibit limited partners from advancing claims that otherwise might raise issues as to compliance with fiduciary duties or applicable law. For example, that agreement provides that the general partner may take into account the interests of parties other than us in resolving conflicts of interest. It also provides that in the absence of bad faith by the general partner, the resolution of a conflict by the general partner will not be a breach of any duty. The provisions relating to the general partner apply equally to KMR as its delegate. It is not necessary for a limited partner to sign our limited partnership agreement in order for the limited partnership agreement to be enforceable against that person.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for U.S. federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. To maintain our status as a partnership for U.S. federal income tax purposes, current law requires that 90% or more of our gross income for every taxable year consist of “qualifying income,” as defined in Section 7704 of the Internal Revenue Code of 1986, as amended, which we refer to as the Code. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, which we refer to as the IRS, on this or any other matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible under certain circumstances for such an entity to be treated as a corporation for U.S. federal income tax purposes. If we were to be treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the amount of distributions we pay, and in the value of our common units.

Current law or our business may change, causing us to be treated as a corporation for U.S. federal income tax purposes or otherwise subjecting us to entity-level taxation. Members of Congress are considering substantive changes to the existing U.S. federal income tax laws that could affect the tax treatment of certain publicly-traded partnerships. For example, federal income tax legislation recently has been considered by Congress that would eliminate partnership tax treatment for certain publicly-traded partnerships. Although the legislation most recently considered by Congress would not appear to affect our tax treatment as a partnership for U.S. federal income tax purposes, we are unable to predict whether any other proposals will ultimately be enacted. Any such changes could negatively impact our cash flows and the value of our common units.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are now subject to an entity-level tax on the portion of our total revenue that is generated in Texas. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. This tax reduces, and the imposition of such a tax on us by another state will reduce, the cash available for distribution to our common unitholders.

Our partnership agreement provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws or interpretations thereof may or may not be applied retroactively. Although we are unable to predict whether any of these changes or any other proposals will ultimately be enacted, any changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were

to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our common unitholders.

If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our common unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our common unitholders and our general partner because the costs will reduce our cash available for distribution.

Our common unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our common unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, they are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us. Common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If a common unitholder sells its common units, the common unitholder will recognize a gain or loss equal to the difference between the amount realized and that common unitholder's adjusted tax basis in those common units. Because distributions in excess of a common unitholder's allocable share of our net taxable income decrease that unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units sold will, in effect, become taxable income allocated to that unitholder if the unitholder sells such common units at a price greater than that unitholder's tax basis in those common units, even if the price received is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized may include a common unitholder's share of our nonrecourse liabilities, if a unitholder sells its common units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Any tax-exempt entity or non-U.S. person should consult its tax advisor before investing in our common units.

Our treatment of a purchaser of common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of our common units.

Because we cannot match transferors and transferees of common units, we are required to maintain the uniformity of the economic and tax characteristics of these common units in the hands of the purchasers and sellers of these common units. We do so by adopting certain depreciation conventions that do not conform to all aspects of the U.S. Treasury regulations. A successful IRS challenge to these conventions could adversely affect the tax benefits to a common unitholder of ownership of our common units and could have a negative impact on the value of our common units or result in audit adjustments to a common unitholder's tax returns.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Our counsel is unable to opine on the validity of such filing positions.

We adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and the common unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our common unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their adjustment under Section 743(b) of the Code allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the adjustment under Section 743(b) of the Code attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our common unitholders and our general partner. It also could affect the amount of gain from our common unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our common unitholders' or our general partner's tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in a termination of our partnership for U.S. federal income tax purposes.

We will be considered to have terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within any twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income being includable in the common unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

A common unitholder whose common units are loaned to a "short seller" to cover a short sale may be considered as having disposed of those common units. If so, the common unitholder would no longer be treated for U.S. federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for U.S. federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the common unitholder and any cash distributions received by the common unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, common unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

The issuance of additional i-units may cause more taxable income and gain to be allocated to the common units.

The i-units we issue to KMR generally are not allocated income, gain, loss or deduction for U.S. federal income tax purposes until such time as we are liquidated. Therefore, the issuance of additional i-units may cause more taxable income and gain to be allocated to the common unitholders.

As a result of investing in our common units, a common unitholder may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to U.S. federal income taxes, our common unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our common unitholders will likely be required to file foreign, state and local income tax returns and pay foreign, state and local income taxes in some or all of these various jurisdictions. Further, our common unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in numerous states in the United States and in Canada. It is the responsibility of each common unitholder to file all required U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Risks Related to Ownership of Our Common Units if We or KMI Defaults on Debt

Unitholders may have negative tax consequences if we default on our debt or sell assets.

If we default on any of our debt, the lenders will have the right to sue us for non-payment. Such an action could cause an investment loss and cause negative tax consequences for unitholders through the realization of taxable income by unitholders without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, unitholders could have increased taxable income without a corresponding cash distribution.

There is the potential for a change of control of our general partner if KMI defaults on debt.

KMI indirectly owns all the common stock of Kinder Morgan G.P., Inc., our general partner. If KMI or Kinder Morgan Kansas, Inc. defaults on its debt, then the lenders under such debt, in exercising their rights as lenders, could acquire control of our general partner or otherwise influence our general partner through control of KMI or Kinder Morgan Kansas, Inc.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

See Note 16 to our consolidated financial statements included elsewhere in this report.

Item 4. Mine Safety Disclosures

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95.1 to this annual report.

PART II

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

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported on the New York Stock Exchange, the principal market in which our common units are traded, the amount of cash distributions declared per common and Class B unit, and the fractional i-unit distribution declared per i-unit.

	<u>Price Range</u>		<u>Declared Cash Distributions</u>	<u>i-unit Distributions</u>
	<u>High</u>	<u>Low</u>		
2011				
First Quarter	\$ 74.51	\$ 69.66	\$ 1.14	0.017102
Second Quarter	78.00	69.50	1.15	0.017895
Third Quarter.....	74.00	63.42	1.16	0.017579
Fourth Quarter	84.95	65.00	1.16	0.014863
2010				
First Quarter	\$ 65.55	\$ 58.00	\$ 1.07	0.017863
Second Quarter	69.33	57.40	1.09	0.018336
Third Quarter	69.90	63.15	1.11	0.017844
Fourth Quarter	71.72	68.19	1.13	0.017393

Distribution information is for distributions declared with respect to that quarter. The declared distributions were paid within 45 days after the end of the quarter. We currently expect to declare cash distributions of \$4.98 per unit for 2012; however, no assurance can be given that we will be able to achieve this level of distribution.

As of January 31, 2012, there were approximately 443,000 holders of our common units (based on the number of record holders and individual participants in security position listings), one holder of our Class B units and one holder of our i-units.

For information on our equity compensation plans, see Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Equity Compensation Plan Information" and Note 12 "Commitments and Contingent Liabilities—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors" to our consolidated financial statements included elsewhere in this report.

We did not repurchase any units during the fourth quarter of 2011 or sell any unregistered units in the fourth quarter of 2011.

Item 6. Selected Financial Data

The following tables set forth, for the periods and at the dates indicated, our summary historical financial and operating 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.

	Year Ended December 31,				
	2011(e)	2010(e)	2009(e)	2008(f)	2007(g)
(In millions, except per unit and ratio data)					
Income and Cash Flow Data:					
Revenues	\$ 8,211.2	\$ 8,077.7	\$ 7,003.4	\$ 11,740.3	\$ 9,217.7
Operating income	\$ 1,670.5	\$ 1,605.1	\$ 1,515.1	\$ 1,551.5	\$ 807.7
Earnings from equity investments	\$ 311.1	\$ 223.1	\$ 189.7	\$ 160.8	\$ 69.7
Income from continuing operations.....	\$ 1,268.4	\$ 1,327.1	\$ 1,283.8	\$ 1,317.2	\$ 423.4
Income from discontinued operations(a).....	\$ -	\$ -	\$ -	\$ 1.3	\$ 173.9
Net income	\$ 1,268.4	\$ 1,327.1	\$ 1,283.8	\$ 1,318.5	\$ 597.3
Limited Partners’ interest in net income (loss).....	\$ 82.8	\$ 431.4	\$ 331.7	\$ 499.0	\$ (21.3)
Limited Partners’ net income (loss) per unit:					
Income (loss) per unit from continuing operations.....	\$ 0.25	\$ 1.40	\$ 1.18	\$ 1.94	\$ (0.82)
Income from discontinued operations	-	-	-	-	0.73
Net income (loss) per unit	<u>\$ 0.25</u>	<u>\$ 1.40</u>	<u>\$ 1.18</u>	<u>\$ 1.94</u>	<u>\$ (0.09)</u>
Per unit cash distribution declared(b).....	\$ 4.61	\$ 4.40	\$ 4.20	\$ 4.02	\$ 3.48
Ratio of earnings to fixed charges(c).....	3.16	3.50	3.82	3.77	2.13
Capital expenditures.....	\$ 1,199.5	\$ 1,000.9	\$ 1,323.8	\$ 2,533.0	\$ 1,691.6
Balance Sheet Data (at end of period):					
Net property, plant and equipment	\$ 15,595.8	\$ 14,603.9	\$ 14,153.8	\$ 13,241.4	\$ 11,591.3
Total assets	\$ 24,102.7	\$ 21,861.1	\$ 20,262.2	\$ 17,885.8	\$ 15,177.8
Long-term debt(d)	\$ 11,159.5	\$ 10,277.4	\$ 9,997.7	\$ 8,274.9	\$ 6,455.9

- (a) Represents income from the operations of our North System natural gas liquids pipeline system. Due to the October 2007 sale of our North System, we accounted for the North System business as a discontinued operation. In 2008, we recorded incremental gain adjustments of \$1.3 million related to our sale of the North System, and except for this gain adjustment on our disposal of the North System, we recorded no other financial results from the operations of the North System during 2008. The 2007 amount includes gains of \$152.8 million on the disposal of our North System.
- (b) Represents the amount of cash distributions declared with respect to that year.
- (c) For the purpose of computing the ratio of earnings to fixed charges, earnings are defined as income from continuing operations before income taxes, equity earnings (including amortization of excess cost of equity investments) and unamortized capitalized interest, plus fixed charges and distributed income of equity investees. Fixed charges are defined as the sum of interest on all indebtedness (excluding capitalized interest), amortization of debt issuance costs and that portion of rental expense which we believe to be representative of an interest factor.
- (d) Excludes value of interest rate swaps. Increases to long-term debt for value of interest rate swaps totaled \$1,078.9 million as of December 31, 2011, \$604.9 million as of December 31, 2010, \$332.5 million as of December 31, 2009, \$951.3 million as of December 31, 2008 and \$152.2 million as of December 31, 2007.
- (e) For each of the years 2011, 2010 and 2009, includes results of operations for net assets acquired since effective dates of acquisition. For further information on these acquisitions, see Note 3 to our consolidated financial statements included elsewhere in this report.
- (f) Includes results of operations for the terminal assets acquired from Chemserve, Inc., and the refined petroleum products terminal located in Phoenix, Arizona acquired from ConocoPhillips since effective dates of acquisition. We acquired the terminal assets from Chemserve, Inc. effective August 15, 2008, and we acquired the refined petroleum products terminal from ConocoPhillips effective December 10, 2008. The increase in overall revenues in 2008 was primarily due to incremental revenues earned from the sales of natural gas by our Natural Gas Pipelines business segment.
- (g) Includes results of operations for the remaining 50.2% interest in the Cochin pipeline system that we did not already own, the Vancouver Wharves bulk marine terminal, and the bulk terminal assets and operations acquired from Marine Terminals, Inc. since

effective dates of acquisition. We acquired the remaining interest in Cochin effective January 1, 2007, the Vancouver Wharves terminal effective May 30, 2007, and the assets and operations from Marine Terminals, Inc. effective September 1, 2007. Also includes results of operations for the net assets of Trans Mountain for the four months prior to the acquisition date. We acquired the net assets of Trans Mountain from KMI on April 30, 2007.

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 included elsewhere in this report. 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 2011, 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 below in "—Information Regarding Forward-Looking Statements."

General

Our business model, through our ownership and operation of energy related assets, is built to support two principal components:

- helping customers by providing energy, bulk commodity and liquids products transportation, storage and distribution; and
- creating long-term value for our unitholders.

To achieve these objectives, we focus on providing fee-based services to customers from a business portfolio consisting of energy-related pipelines, bulk and liquids terminal facilities, and carbon dioxide and petroleum reserves. Our reportable business segments are based on the way our management organizes our enterprise, and each of our business segments represents a component of our enterprise that engages in a separate business activity and for which discrete financial information is available.

Our reportable business segments are:

- Products Pipelines—the ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;
- Natural Gas Pipelines—the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems, plus the ownership and/or operation of associated natural gas processing and treating facilities;
- CO₂—(i) the production, transportation and marketing of carbon dioxide, referred to as CO₂, to oil fields that use CO₂ to increase production of oil; (ii) ownership interests in and/or operation of oil fields in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas;
- Terminals—the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the United States and portions of Canada; and
- Kinder Morgan Canada—(i) 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; (ii) the 33 1/3% interest in the Express crude oil pipeline

system, which connects Canadian and U.S. producers to refineries located in the U.S. Rocky Mountain and Midwest regions; and (iii) the Jet Fuel aviation turbine fuel pipeline that serves the Vancouver (Canada) International Airport.

As an energy infrastructure owner and operator in multiple facets of the United States' and Canada's various energy businesses 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. Many of our operations are regulated by various U.S. and Canadian regulatory bodies and a portion of our business portfolio (including our Kinder Morgan Canada business segment, the Canadian portion of our Cochin Pipeline, and our bulk and liquids terminal facilities located in Canada) uses the local Canadian dollar as the functional currency for its Canadian operations and enters into foreign currency-based transactions, both of which affect segment results due to the inherent variability in U.S. - Canadian dollar exchange rates. To help understand our reported operating results, all of the following references to "foreign currency effects" or similar terms in this section represent our estimates of the changes in financial results, in U.S. dollars, resulting from fluctuations in the relative value of the Canadian dollar to the U.S. dollar. The references are made to facilitate period-to-period comparisons of business performance and may not be comparable to similarly titled measures used by other registrants.

The profitability of our refined petroleum products pipeline transportation business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. Transportation 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.

With respect to our interstate natural gas pipelines and related storage facilities, 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 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, in our Texas Intrastate Pipeline business, we currently derive approximately 75% of our sales and transport margins from long-term transport and sales contracts that include requirements with minimum volume payment obligations. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2011, the remaining average contract life of our natural gas transportation contracts (including our intrastate pipelines) was approximately eight years.

Our CO₂ sales and transportation business primarily has contracts with minimum volume requirements, which as of December 31, 2011, had a remaining average contract life of four years (this remaining average contract life includes intercompany sales; when we eliminate intercompany sales, the remaining average contract life is approximately five years). Carbon dioxide 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 contracts making deliveries in 2012, and utilizing the average oil price per barrel contained in our 2012 budget, approximately 70% of our contractual volumes are based on a fixed fee or floor price, and 30% fluctuate with the price of oil (these percentages include intercompany sales; when we eliminate intercompany sales, the percentages are 72% and 28%, respectively). In the long-term, our success in this business is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In our CO₂ 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, natural gas liquids and carbon dioxide 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. Our realized weighted average crude oil price per barrel, with all hedges allocated to oil, was \$69.73 per barrel in 2011, \$59.96 per barrel in 2010 and \$49.55 per barrel in 2009. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged \$92.61 per barrel in 2011, \$76.93 per barrel in 2010 and \$59.02 per barrel in 2009.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. As with our refined petroleum products pipeline 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 coal, petroleum coke, and steel. For the most part, we have contracts for this business that have minimum volume guarantees and are volume based above the minimums. Because these contracts are volume based above the minimums, our profitability from the bulk business can be sensitive to economic conditions. Our liquids terminals business generally has longer-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline 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 is typically 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. 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, floods and droughts 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 our discussions of the operating results of individual businesses that follow (see “—Results of Operations” below), we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods. Continuing our history of making accretive acquisitions and economically advantageous expansions of existing businesses, in 2011, we invested approximately \$2.6 billion for both strategic business acquisitions and expansions of existing assets. Our capital investments have helped us to achieve compound annual growth rates in cash distributions to our limited partners of 4.8%, 4.7% and 7.2%, respectively, for the one-year, three-year and five-year periods ended December 31, 2011.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately \$1.7 billion for our 2012 capital expansion program, including small acquisitions and investment contributions. Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

In addition, we regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. While there are currently no unannounced purchase agreements for the acquisition 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. Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

Our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, including our public debt and equity offerings in 2011, please see “—Liquidity and Capital Resources” below.

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 U.S. generally accepted accounting principles 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) the economic useful lives of our assets; (ii) the fair values used to assign purchase price from business combinations, determine possible asset impairment charges, and calculate the annual goodwill impairment test; (iii) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (iv) provisions for uncollectible accounts receivables; (v) exposures under contractual indemnifications; and (vi) unbilled revenues.

For a summary of our significant accounting policies, see Note 2 to our consolidated financial statements included elsewhere in this report. 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.

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.

These environmental liability adjustments are recorded pursuant to our management's requirement to recognize contingent environmental liabilities whenever the associated environmental issue is likely to occur and the amount of our liability can be reasonably estimated. 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 our environmental disclosures, see Note 16 to our consolidated financial statements included elsewhere in this report.

Legal Matters

We are subject to litigation and regulatory proceedings 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; 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. When we identify specific litigation that is expected to continue for a significant period of time, is reasonably possible to occur, and may require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement. 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.

As of December 31, 2011, our most significant ongoing litigation proceedings involved our West Coast Products Pipelines. Transportation rates charged by certain of these pipeline systems are subject to proceedings at the FERC and the CPUC involving shipper challenges to the pipelines' interstate and intrastate (California) rates, respectively. For more information on our regulatory proceedings, see Note 16 to our consolidated financial statements included elsewhere in this report.

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 our goodwill for impairment on May 31 of each year. There were no impairment charges resulting from our May 31, 2011 impairment testing, and no event indicating an impairment has occurred subsequent to that date. For more information on our goodwill, see Notes 2 and 7 to our consolidated financial statements included elsewhere in this report.

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, 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. For more information on our amortizable intangibles, see Note 7 to our consolidated financial statements included elsewhere in this report.

Estimated Net Recoverable Quantities of Oil and Gas

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted or amortized into income, and the presentation of supplemental information on oil and gas producing activities. The expected future cash flows to be generated by oil and gas producing properties used in testing for impairment of such properties also rely in part on estimates of net recoverable quantities of oil and gas.

Proved reserves are the estimated quantities of oil and gas that geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. For more information on our ownership interests in the net quantities of proved oil and gas reserves and our measures of discounted future net cash flows from oil and gas reserves, please see Note 20 to our consolidated financial statements included elsewhere in this report.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices 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 U.S. generally accepted accounting principles, 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.

Since it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to unfavorable changes in commodity prices—a perfectly effective hedge—we often enter into hedges that are not completely effective in those instances where we believe to do so would be better than not hedging at all. But because the part of such hedging transactions that is not effective in offsetting undesired changes in commodity prices (the ineffective portion) is required to be recognized currently in earnings, our 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 example, when we purchase a commodity at one location and sell it at another, we may be unable to hedge completely our exposure to a differential in the price of the product between these two locations; accordingly, our financial statements may reflect some volatility due to these hedges. For more information on our hedging activities, see Note 13 to our consolidated financial statements included elsewhere in this report.

Results of Operations

Consolidated

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)			
Products Pipelines(b)	\$ 463.1	\$ 504.5	\$ 584.5
Natural Gas Pipelines(c)	774.2	836.3	789.6
CO ₂ (d)	1,098.6	965.5	782.9
Terminals(e)	704.5	641.3	599.0
Kinder Morgan Canada(f)	201.6	181.6	154.5
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	3,242.0	3,129.2	2,910.5
Depreciation, depletion and amortization expense	(954.5)	(904.8)	(850.8)
Amortization of excess cost of equity investments	(6.7)	(5.8)	(5.8)
General and administrative expenses(g)	(472.7)	(375.2)	(330.3)
Interest expense, net of unallocable interest income(h)	(531.0)	(506.4)	(431.3)
Unallocable income tax expense	(8.7)	(9.9)	(8.5)
Net income	1,268.4	1,327.1	1,283.8
Net income attributable to noncontrolling interests(i)	(10.6)	(10.8)	(16.3)
Net income attributable to Kinder Morgan Energy Partners, L.P.	<u>\$ 1,257.8</u>	<u>\$ 1,316.3</u>	<u>\$ 1,267.5</u>

- (a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
- (b) 2011 amount includes (i) a \$168.2 million increase in expense associated with rate case liability adjustments; (ii) a \$60.0 million increase in expense associated with rights-of-way lease payment liability adjustments for periods prior to 2011; (iii) an \$8.6 million increase in expense associated with environmental liability adjustments; (iv) a \$6.7 million increase in expense associated with legal liability adjustments related to a litigation matter involving our Calnev pipeline's Las Vegas terminal operations; (v) a \$12.1 million increase in income from both the disposal of property and the settlement of a legal matter related to the sale of a portion of our Gaffey Street, California land; and (vi) a \$0.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense). 2010 amount includes (i) a \$172.0 million increase in expense associated with rate case liability adjustments; (ii) an \$18.0 million decrease in income associated with combined property environmental expenses and the demolition of physical assets in preparation for the sale of our Gaffey Street, California land; (iii) a \$2.5 million increase in expense associated with environmental liability adjustments; (iv) an \$8.8 million gain from the sale of a 50% ownership interest in the Cypress pipeline system and the revaluation of our remaining interest to fair value; and (v) a \$0.7 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions. 2009 amount includes (i) a \$23.0 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries; (ii) an \$18.0 million increase in expense associated with rate case and other legal liability adjustments; (iii) an \$11.5 million increase in expense associated with environmental liability adjustments; (iv) a \$1.7 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions; and (v) a \$0.2 million increase in income from hurricane casualty gains.
- (c) 2011 amount includes a \$167.2 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value, and a \$9.7 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2010 amount includes a \$0.4 million increase in income from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition. 2009 amount includes (i) a \$7.8 million increase in income from hurricane casualty gains; (ii) a decrease in income of \$5.6 million resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas; and (iii) a \$0.1 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries.
- (d) 2011, 2010 and 2009 amounts include a \$5.2 million unrealized gain, a \$5.3 million unrealized gain and a \$13.5 million unrealized loss, respectively, related to derivative contracts used to hedge forecasted crude oil sales.
- (e) 2011 amount includes (i) a \$4.8 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense); (ii) a \$4.3 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (iii) a \$2.2 million increase in income associated with the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.; (iv) a \$1.5 million increase in income from the sale of our ownership interest in

Arrow Terminals B.V.; (v) a \$1.3 million increase in income from adjustments associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009; (vi) a \$7.6 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses; (vii) a \$2.0 million increase in expense associated with environmental liability adjustments; (viii) a \$0.6 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal; and (ix) a combined \$0.5 million decrease in income from property write-offs and expenses associated with the on-going dissolution of our partnership interest in Globalplex Handling. 2010 amount includes (i) a combined \$7.4 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses; (ii) a combined \$4.1 million decrease in income associated with a write-down of the carrying value of net assets to be sold to their estimated fair values as of December 31, 2010 (associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009); (iii) a \$0.6 million increase in expense related to storm and flood clean-up and repair activities; (iv) a \$6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; and (v) a \$0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition. 2009 amount includes (i) a \$24.0 million increase in income from hurricane and fire casualty gains and clean-up and repair activities; (ii) a \$0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal; (iii) a \$0.9 million increase in expense associated with environmental liability adjustments; and (iv) a \$0.7 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries.

- (f) 2011 amount includes a \$3.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense). 2009 amount includes a \$14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to Trans Mountain's carrying amount of the previously established deferred tax liability, and a \$3.7 million decrease in expense due to a certain non-cash accounting adjustment related to book tax accruals made by the Express pipeline system.
- (g) 2011 amount includes (i) a combined \$89.9 million increase in non-cash compensation expense (including \$87.1 million related to a special bonus expense to non-senior management employees), allocated to us from KMI; however, we do not have any obligation, nor did we pay any amounts related to this expense; (ii) a combined \$4.1 million increase in expense for unallocated legal expenses and certain asset and business acquisition expenses; and (iii) a \$0.2 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount includes (i) a \$4.6 million increase in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts related to this expense); (ii) a \$4.2 million increase in expense for certain asset and business acquisition costs; (iii) a \$1.6 million increase in legal expense associated with items disclosed in these footnotes such as legal settlements and pipeline failures; and (iv) a \$0.2 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2009 amount includes (i) a \$5.7 million increase in non-cash compensation expense, allocated to us from KMI (we do not have any obligation, nor did we pay any amounts related to this expense); (ii) a \$2.3 million increase in expense for certain asset and business acquisition costs, which under prior accounting standards would have been capitalized; (iii) a \$1.3 million increase in expense for certain land transfer taxes associated with our April 30, 2007 Trans Mountain acquisition; and (iv) a \$2.7 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
- (h) 2011, 2010 and 2009 amounts include increases in imputed interest expense of \$0.7 million, \$1.1 million and \$1.6 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
- (i) 2011, 2010 and 2009 amounts include decreases of \$6.6 million, \$4.6 million and \$0.7 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2011, 2010 and 2009 items previously disclosed in these footnotes.

Segment earnings before depreciation, depletion and amortization expenses

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

Total segment earnings before depreciation, depletion and amortization expenses increased by \$112.8 million (4%) in 2011 compared to 2010; however, this overall increase in earnings included a decrease of \$214.0 million from the effect of the certain items described in the footnotes to the table above (which combined to decrease total segment EBDA by \$396.5 million and \$182.5 million in 2011 and 2010, respectively). The remaining \$326.8 million (10%) increase in total segment earnings before depreciation, depletion and amortization in 2011 compared to 2010 resulted from better

performance from all five of our reportable business segments, primarily due to increases attributable to our CO₂ (\$133.2 million), Natural Gas Pipelines (\$115.2 million), and Terminals (\$54.6 million) business segments.

In 2010, total segment earnings before depreciation, depletion and amortization increased \$218.7 million (8%) compared to 2009, and the overall increase included a \$132.2 million decrease in earnings from the effect of the certain items described in the footnotes to the table above (combining to decrease total segment EBDA by \$182.5 million and \$50.3 million in 2010 and 2009, respectively). The remaining \$350.9 million (12%) increase in total segment earnings before depreciation, depletion and amortization in 2010 versus 2009 resulted from better performance from all five of our reportable business segments, mainly due to increases attributable to our CO₂ and Terminals business segments.

Products Pipelines

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except operating statistics)		
Revenues	\$ 914.0	\$ 883.0	\$ 826.6
Operating expenses(a)	(499.7)	(414.6)	(269.5)
Other income (expense)(b)	10.0	(4.2)	(0.6)
Earnings from equity investments	50.6	33.1	29.0
Interest income and Other, net(c).....	8.2	16.4	12.4
Income tax expense(d).....	(20.0)	(9.2)	(13.4)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	<u>\$ 463.1</u>	<u>\$ 504.5</u>	<u>\$ 584.5</u>
Gasoline (MMBbl)(e)	398.0	403.5	400.1
Diesel fuel (MMBbl)	148.9	148.3	143.2
Jet fuel (MMBbl)	110.5	106.2	111.4
Total refined product volumes (MMBbl).....	657.4	658.0	654.7
Natural gas liquids (MMBbl).....	26.1	25.2	26.5
Total delivery volumes (MMBbl)(f)	683.5	683.2	681.2
Ethanol (MMBbl)(g).....	30.4	29.9	23.1

- (a) 2011, 2010 and 2009 amounts include increases in expense of \$8.6 million, \$2.5 million and \$11.5 million, respectively, associated with environmental liability adjustments. 2011 amount also includes a \$168.2 million increase in expense associated with rate case liability adjustments, a \$60.0 million increase in expense associated with rights-of-way lease payment liability adjustments, and a \$6.7 million increase in expense associated with legal liability adjustments related to a litigation matter involving our Calnev pipeline's Las Vegas terminal operations. 2010 amount also includes a \$172.0 million increase in expense associated with rate case liability adjustments, and a \$14.1 million increase in expense associated with environmental clean-up expenses and the demolition of physical assets in preparation for the sale of our Gaffey Street, California land. 2009 amount also includes a \$23.0 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries, and an \$18.0 million increase in expense associated with rate case and other legal liability adjustments.
- (b) 2011 amount includes a \$10.8 million increase in income from the sale of a portion of our Gaffey Street, California land. 2010 amount includes disposal losses of \$3.9 million related to the retirement of our Gaffey Street, California land. 2009 amount includes a gain of \$0.2 million from hurricane casualty indemnifications.
- (c) 2011 amount includes a \$1.3 million increase in income from the settlement of a legal matter related to the sale of a portion of our Gaffey Street, California land. 2010 and 2009 amounts include increases in income of \$0.7 million and \$1.7 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions. 2010 amount also includes an \$8.8 million gain from the sale of a 50% ownership interest in the Cypress pipeline system and the revaluation of our remaining interest to fair value.
- (d) 2011 amount includes a \$0.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense).
- (e) Volumes include ethanol pipeline volumes.
- (f) Includes Pacific, Plantation, Calnev, Central Florida, Cochin, and Cypress pipeline volumes.
- (g) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

Combined, the certain items described in the footnotes to the table above accounted for decreases in segment earnings before depreciation, depletion and amortization expenses of \$48.3 million in 2011, and \$132.4 million in 2010, when compared with the respective prior year. Following is information related to the segment's (i) remaining \$6.9 million (1%) and \$52.4 million (8%) increases in earnings before depreciation, depletion and amortization; and (ii) \$31.0 million (4%) and \$56.4 million (7%) increases in operating revenues in both 2011 and 2010, when compared with the respective prior year:

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline.....	\$	17.5 53%	\$	29.9 66%
Plantation Pipeline		8.6 19 %		1.2 6 %
West Coast Terminals.....		8.5 11 %		9.8 10 %
Pacific operations		(17.6) (6)%		(11.1) (3)%
Calnev Pipeline.....		(4.6) (8)%		(3.4) (5)%
Transmix operations		(3.5) (9)%		2.8 6 %
All others (including eliminations)		(2.0) (2)%		1.8 1 %
Total Products Pipelines.....	\$	6.9 1 %	\$	31.0 4 %

The primary increases and decreases in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in 2011 compared to 2010 were attributable to the following:

- a \$17.5 million (53%) increase from our Cochin natural gas liquids pipeline system—largely related to a 33% increase in system-wide throughput volumes, partially offset by increased income tax expense due to the year-over-year increase in pre-tax income;
- an \$8.6 million (19%) increase from our approximate 51% equity interest in the Plantation pipeline system. The increase in Plantation's earnings was primarily due to higher oil loss allowance revenues, a 4% increase in transport volumes, and the absence of an expense from the write-off of an uncollectible receivable in the first quarter of 2010;
- an \$8.5 million (11%) increase from our West Coast terminal operations—due mainly to the completion of various terminal expansion projects that increased liquids tank capacity, and partly to higher rates on existing storage;
- a \$17.6 million (6%) decrease from our Pacific operations—due largely to an \$11.1 million decrease in revenues and a \$6.1 million increase in combined operating expenses. The decrease in revenues was primarily due to lower average tariffs, due both to lower rates on the system's East Line deliveries as a result of rate case settlements since the end of 2010 and lower military tenders. This decrease was partially offset by higher terminal revenues attributable to a 10% increase in ethanol handling volumes. The increase in operating expenses was mainly due to a \$7.5 million increase in expense associated with liability adjustments made pursuant to an adverse tentative court decision on the amount of 2011 rights-of-way lease payment obligations;
- a \$4.6 million (8%) decrease from our Calnev Pipeline—due largely to a 21% drop in ethanol handling volumes that related to both lower deliveries to the Las Vegas market and incremental ethanol blending services offered by a competing terminal; and
- a \$3.5 million (9%) decrease from our Transmix processing operations—due mainly to a \$4.2 million decrease in income from lower product gains relative to 2010.

Year Ended December 31, 2010 versus Year Ended December 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	\$	40.0 15%	\$	49.9 13%
Southeast Terminals		14.9 28 %		12.0 15 %
West Coast Terminals.....		10.5 16 %		10.7 12 %
Plantation Pipeline		3.2 8 %		(0.3) (1)%
Central Florida Pipeline		2.9 6 %		1.4 2 %
Cochin Pipeline.....		(20.4) (38)%		(16.6) (27)%
All others (including eliminations)		1.3 1 %		(0.7) (1)%
Total Products Pipelines.....	\$	52.4 8 %	\$	56.4 7 %

The primary increases and decreases in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in 2010 compared to 2009 were attributable to the following:

- a \$40.0 million (15%) increase from our Pacific operations—due largely to a \$49.9 million (13%) increase in operating revenues, consisting of a \$32.1 million (11%) increase in mainline delivery revenues and a \$17.8 million (17%) increase in fee-based terminal revenues. The increase in pipeline delivery revenues was attributable to higher average tariff rates in 2010 (due in part to FERC-approved rate increases) and to military tender rate increases. Overall mainline delivery volumes were essentially flat across both years. The increase in terminal revenues was mainly attributable to incremental ethanol handling services that were due in part to mandated increases in ethanol blending rates in California since the end of 2009;
- a \$14.9 million (28%) increase from our Southeast terminal operations—due to both increased ethanol throughput (driven by continued high demand during 2010 in the ethanol and biofuels markets) and higher product inventory gains relative to the prior year;
- a \$10.5 million (16%) increase from our West Coast terminal operations—driven by higher warehousing revenues and incremental customers at our combined Carson/Los Angeles Harbor terminal system, higher biodiesel revenues from our two Portland, Oregon liquids facilities, and incremental earnings contributions from the terminals' Portland, Oregon Airport pipeline, which was acquired on July 31, 2009;
- a \$3.2 million (8%) increase from our equity investment in Plantation. The increase in Plantation's earnings was driven by both higher products transportation revenues and higher oil loss allowance revenues. The increase in transportation revenues was due to a 2% increase in pipeline throughput volumes, resulting from both an upgrade at a refinery in Louisiana and to mainline allocation on a competing pipeline. The increase in oil loss allowance revenues was associated with the increase in volumes and an increase in products prices, relative to the prior year;
- a \$2.9 million (6%) increase from our Central Florida Pipeline—due mainly to incremental product inventory gains and partly to higher ethanol handling revenues; and
- a \$20.4 million (38%) decrease from our Cochin pipeline system—attributable to a \$16.6 million (27%) drop in revenues and a \$3.8 million (35%) increase in operating expenses. The lower revenues reflected a 32% decline in propane delivery volumes, due to milder weather, a drop in grain drying demand, and the negative impacts from unfavorable tariff changes in 2010. The increase in operating expenses was primarily related to favorable settlements reached in the first quarter of 2009 with the seller of the remaining approximate 50.2% interest in the Cochin pipeline system that we purchased on January 1, 2007.

Natural Gas Pipelines

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except operating statistics)		
Revenues(a)	\$ 4,265.1	\$ 4,416.5	\$ 3,806.9
Operating expenses(b)	(3,551.6)	(3,750.3)	(3,193.0)
Other income(c)	-	-	7.8
Earnings from equity investments	227.2	169.1	141.8
Interest income and Other, net(d)	(162.4)	4.3	31.8
Income tax expense	(4.1)	(3.3)	(5.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 774.2	\$ 836.3	\$ 789.6
Natural gas transport volumes (Bcf)(e)	2,925.0	2,584.2	2,285.1
Natural gas sales volumes (Bcf)(f)	804.7	797.9	794.5

- (a) 2010 amount includes a \$0.4 million increase in revenues from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition.
- (b) 2011 amount includes a \$9.7 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2009 amount includes a \$5.6 million decrease in income resulting from unrealized mark to market losses due to the discontinuance of hedge accounting at Casper Douglas. Beginning in the second quarter of 2008, our Casper and Douglas gas processing operations discontinued hedge accounting, and the last of the related derivative contracts expired in December 2009. 2009 amount also includes a \$0.1 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries.
- (c) 2009 amount represents gains from hurricane casualty indemnifications.
- (d) 2011 amount includes a \$167.2 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value.
- (e) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC and Texas intrastate natural gas pipeline group, and for 2011 only, Fayetteville Express Pipeline LLC.
- (f) Represents Texas intrastate natural gas pipeline group volumes.

Combined, the certain items described in the footnotes to the table above accounted for (i) decreases of \$177.3 million and \$1.7 million, respectively, in segment earnings before depreciation, depletion and amortization expenses in 2011 and 2010; and (ii) a decrease of \$0.4 million and an increase of \$0.4 million, respectively, in segment revenues in 2011 and 2010, when compared with the respective prior year.

Following is information related to the segment's remaining (i) \$115.2 million (14%) and \$48.4 million (6%) increases in earnings before depreciation, depletion and amortization; and (ii) \$151.0 million (3%) decrease and \$609.2 million (16%) increase in operating revenues in 2011 and 2010, when compared with the respective prior year:

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA		Revenues		
	increase/(decrease)		increase/(decrease)		
	(In millions, except percentages)				
KinderHawk Field Services(a).....	\$	92.5	n/a	\$ 99.4	n/a
Fayetteville Express Pipeline(b)		23.8	n/a	n/a	n/a
Midcontinent Express Pipeline(b).....		12.6	42 %	n/a	n/a
Casper and Douglas Natural Gas Processing		7.6	36 %	19.9	19 %
Texas Intrastate Natural Gas Pipeline Group.....		5.8	2 %	(251.5)	(6)%
Kinder Morgan Interstate Gas Transmission		(18.2)	(17)%	(29.6)	(17)%
Trailblazer Pipeline.....		(11.3)	(25)%	(7.6)	(14)%
All others (including eliminations)		2.4	1 %	18.4	10 %
Total Natural Gas Pipelines	\$	115.2	14 %	\$ (151.0)	(3)%

a) Equity investment until July 1, 2011. See Note (b).

(b) Equity investment. We record earnings under the equity method of accounting, but we receive distributions in amounts essentially equal to equity earnings plus depreciation and amortization expenses less sustaining capital expenditures.

The primary increases and decreases in our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses in 2011 compared to 2010 were attributable to the following:

- a \$92.5 million increase from incremental earnings from our now wholly-owned KinderHawk Field Services LLC. For more information about our two KinderHawk acquisitions, see Note 3 to our consolidated financial statements included elsewhere in this report;
- a \$23.8 million increase from incremental equity earnings from our 50% interest in the Fayetteville Express pipeline system, which began firm contract transportation service on January 1, 2011;
- a \$12.6 million (42%) increase in equity earnings from our 50% interest in the Midcontinent Express pipeline system—driven by higher transportation revenues and by the June 2010 completion of an expansion project that increased the system's Zone 1 transportation capacity from 1.5 billion to 1.8 billion cubic feet per day, and Zone 2 capacity from 1.0 billion to 1.2 billion cubic feet per day;
- a \$7.6 million (36%) increase from our Casper Douglas gas processing operations—attributable to a 40% increase in net processing spreads;
- a \$5.8 million (2%) increase from our Texas intrastate natural gas pipeline group—primarily due to (i) a \$29.8 million increase due to higher margins from both natural gas storage and transportation services (due to favorable storage price spreads and a 15% increase in transportation volumes); (ii) an \$11.3 million increase due to incremental equity earnings from our 50% interest in Eagle Ford Gathering LLC; (iii) a \$23.7 million drop in natural gas sales margin (mainly attributable to higher costs of natural gas supplies relative to sales price); and (iv) a \$12.2 million decrease due to higher operating expenses (attributable primarily to higher pipeline integrity and remediation expenses);
- an \$18.2 million (17%) decrease from our Kinder Morgan Interstate Gas Transmission pipeline system— driven by a \$12.3 million decrease due to lower net fuel recoveries, related to both lower recovery factors resulting from a FERC regulatory settlement reached with shippers that became effective June 1, 2011, and lower average collection prices due to an overall drop in natural gas market prices relative to 2010; and
- an \$11.3 million (25%) decrease from our Trailblazer pipeline system—mainly attributable to both a \$4.8 million increase in expense from the write-off of receivables for under-collected fuel (incremental to the \$9.7 million increase in expense that is described in footnote (b) to the results of operations table above and which relates to periods prior to 2011), and a \$3.3 million decrease in natural gas transmission revenues, due largely to lower transportation base rates implemented in 2011 as a result of a 2010 rate case settlement.

Year Ended December 31, 2010 versus Year Ended December 31, 2009

	EBDA		Revenues	
	Increase/(decrease)		Increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	\$	33.8 360 %	\$	48.1 339 %
KinderHawk Field Services(a).....		19.5 n/a		n/a n/a
Midcontinent Express Pipeline(a).....		15.4 105 %		n/a n/a
Kinder Morgan Louisiana Pipeline		14.1 34 %		42.5 167 %
Casper and Douglas Natural Gas Processing		8.8 71 %		30.5 41 %
Kinder Morgan Interstate Gas Transmission		(17.2) (14)%		3.8 2 %
Texas Intrastate Natural Gas Pipeline Group		(16.0) (4)%		487.6 14 %
Rockies Express Pipeline(a)		(10.0) (10)%		n/a n/a
All others (including eliminations)		- -		(3.3) (3)%
Total Natural Gas Pipelines	\$	48.4 6 %	\$	609.2 16 %

- (a) Equity investments. We record earnings under the equity method of accounting, but we receive distributions in amounts essentially equal to equity earnings plus depreciation and amortization expenses less sustaining capital expenditures.

The primary increases and decreases in our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses in 2010 compared to 2009 were attributable to the following:

- a \$33.8 million (360%) increase from our Kinder Morgan Natural Gas Treating operations—due mainly to our acquisitions of natural gas treating operations from CrossTex Energy, Inc. on October 1, 2009, and from Gas-Chill, Inc. on September 1, 2010. Combined, the acquired operations contributed incremental earnings before depreciation, depletion and amortization of \$33.8 million, revenues of \$48.1 million and operating expenses of \$14.1 million in 2010;
- a \$19.5 million increase due to incremental contributions from our initial 50% equity ownership interest in KinderHawk, acquired on May 21, 2010;
- a \$15.4 million (105%) increase from our equity investment in Midcontinent Express—due primarily to the inclusion of a full year of operations in 2010 and the June 2010 completion of the expansion project described above. Midcontinent Express initiated interim natural gas transportation service for its Zone 1 pipeline segment on April 10, 2009, achieved full Zone 1 service on May 21, 2009, and achieved full Zone 2 service on August 1, 2009;
- a \$14.1 million (34%) increase from our Kinder Morgan Louisiana pipeline system—consisting of a \$36.6 million increase in system operating income and a \$22.5 million decrease in non-operating other income. The increase from operations was mainly due to incremental transportation service (we commenced limited natural gas transportation service in April 2009 and we completed construction and began full transportation service on the system's remaining portions in June 2009). The drop in non-operating income, relative to 2009, reflected lower income pursuant to FERC regulations governing allowances for capital funds that are used for pipeline construction costs (an equity cost of capital allowance);
- an \$8.8 million (71%) increase from our Casper Douglas gas processing operations—primarily attributable to higher natural gas processing spreads. The \$30.5 million (41%) year-to-year increase in revenues was driven by both a 4% increase in natural gas liquids sales volumes and a 41% increase in average natural gas liquids sales prices;
- a \$17.2 million (14%) decrease from our Kinder Morgan Interstate Gas Transmission pipeline system—driven by a \$7.2 million decrease due to lower margins on operational sales of natural gas, and a \$6.8 million decrease due to lower pipeline net fuel recoveries. Both decreases were due mainly to lower average natural gas prices in 2010. KMITG's operational gas sales are primarily made possible by both collection of fuel in kind pursuant to its currently effective gas transportation tariff, and by recoveries of storage cushion gas volumes;
- a \$16.0 million (4%) decrease from our Texas intrastate natural gas pipeline group—driven by (i) a \$15.8 million decrease in earnings from overall storage activities (primarily due to lower price spreads due to unfavorable market conditions relative to 2009); (ii) a \$3.5 million decrease from lower interest income, due to a one-time natural gas loan to a single customer in 2009; (iii) a \$3.4 million decrease due to lower natural gas gains (primarily due to

2009 volume measurement gains related to the normal tracking of natural gas throughout the pipeline system); and (iv) a \$2.8 million decrease in natural gas sales margins, largely attributable to higher costs of natural gas supplies relative to sales prices and less favorable market conditions. The overall decrease in earnings in 2010 versus 2009 was partially offset by a \$9.5 million increase in earnings due to higher natural gas processing margins, due mainly to higher natural gas liquids prices relative to 2009, and a \$3.1 million increase in earnings due to incremental equity earnings from our 40%-owned Endeavor Gathering LLC, acquired effective November 1, 2009; and

- a \$10.0 million (10%) decrease from our 50% interest in the Rockies Express pipeline system. Compared to 2009, Rockies Express' net income (on a 100% basis) dropped \$18.1 million (9%) in 2010. The decrease consisted of (i) a \$70.3 million decrease primarily related to higher interest expenses, net of interest income; and (ii) a \$52.2 million increase from higher system operating income. The increase in interest expenses was due to higher non-cash allowances for borrowed funds used during construction in 2009 (which reduces interest expenses), and to debt obligations shifting from short-term to long-term at higher interest rates in 2010. (Rockies Express issued \$1.7 billion aggregate principal amount of fixed rate senior notes in a private offering in March 2010 to secure permanent financing for the Rockies Express pipeline construction costs). The increase in operating income was driven by incremental transportation service revenues related to the completion and start-up of the Rockies Express-East pipeline segment, the third and final phase of the Rockies Express system. Rockies Express-East began initial pipeline service on June 29, 2009 and began full operations on November 12, 2009.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in both pairs of comparable years primarily relate to the natural gas purchase and sale activities of our Texas intrastate natural gas pipeline group, with the variances from year-to-year in both revenues and operating expenses mainly due to corresponding changes in the intrastate group's average prices and volumes for natural gas purchased and sold. Our intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its natural gas sales revenues are largely offset by corresponding increases and decreases in its natural gas purchase costs. It realizes earnings by capturing the favorable differences between the changes in its gas sales prices, purchase prices and transportation costs, including fuel. Our intrastate group accounted for 85%, 88% and 89%, respectively, of the segment's revenues in 2011, 2010 and 2009, and 93%, 94% and 95%, respectively, of the segment's operating expenses in 2011, 2010 and 2009.

CO₂

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except operating statistics)		
Revenues(a)	\$ 1,416.2	\$ 1,245.7	\$ 1,035.7
Operating expenses	(342.5)	(308.1)	(271.1)
Earnings from equity investments	24.1	22.5	22.3
Interest income and Other, net	5.2	4.5	-
Income tax benefit (expense)	(4.4)	0.9	(4.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 1,098.6	\$ 965.5	\$ 782.9
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(b)	1.3	1.3	1.2
Southwest Colorado carbon dioxide production (net) (Bcf/d)(b)	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(c)	28.6	29.2	30.1
SACROC oil production (net)(MBbl/d)(d)	23.8	24.3	25.1
Yates oil production (gross)(MBbl/d)(c)	21.7	24.0	26.5
Yates oil production (net)(MBbl/d)(d)	9.6	10.7	11.8
Katz oil production (gross)(MBbl/d)(c)	0.5	0.3	0.3
Katz oil production (net)(MBbl/d)(d)	0.4	0.2	0.3
Natural gas liquids sales volumes (net)(MBbl/d)(d)	8.5	10.0	9.5
Realized weighted average oil price per Bbl(e)	\$ 69.73	\$ 59.96	\$ 49.55
Realized weighted average natural gas liquids price per Bbl(f)	\$ 65.61	\$ 51.03	\$ 37.96

- (a) 2011, 2010 and 2009 amounts include unrealized gains of \$5.2 million, unrealized gains of \$5.3 million and unrealized losses of \$13.5 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales.

- (b) Includes McElmo Dome and Doe Canyon sales volumes.
- (c) 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, and an approximately 99% working interest in the Katz Strawn unit.
- (d) Net to us, after royalties and outside working interests.
- (e) Includes all of our crude oil production properties.
- (f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO₂ segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO₂) and crude oil, and the production and marketing of natural gas and natural gas liquids. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and Sales and Transportation Activities.

Combined, the unrealized gains and losses on derivative contracts used to hedge forecasted crude oil sales and described in footnote (a) to the table above decreased both earnings before depreciation, depletion and amortization and revenues by \$0.1 million in 2011 compared to 2010, and increased both earnings before depreciation, depletion and amortization and revenues by \$18.8 million in 2010 compared to 2009. For each of the segment's two primary businesses, following is information related to the remaining (i) \$133.2 million (14%) and \$163.8 million (21%) increases in earnings before depreciation, depletion and amortization; and (ii) \$170.6 million (14%) and \$191.2 million (18%) increases in operating revenues in both 2011 and 2010, when compared with the respective prior year:

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA		Revenues		
	increase/(decrease)		increase/(decrease)		
	(In millions, except percentages)				
Oil and Gas Producing Activities	\$	95.9	14 %	\$ 127.2	13 %
Sales and Transportation Activities		37.3	14 %	55.6	19 %
Intrasegment Eliminations		-	-	(12.2)	(23)%
Total CO ₂	\$	133.2	14 %	\$ 170.6	14 %

The segment's oil and gas producing activities include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants, and generally, earnings from these activities are closely aligned with realized price levels for crude oil and natural gas liquids products. When compared to 2010, the increase in earnings from the segment's oil and gas producing activities in 2011 was mainly due to the following:

- a \$92.1 million (12%) increase due to higher crude oil sales revenues—due to higher average realized sales prices for U.S. crude oil. Our realized weighted average price per barrel of crude oil increased 16% in 2011 versus 2010. The overall increase in crude oil sales revenues was partially offset, however, by a 4% decrease in oil production volumes (volumes presented in the results of operations table above), due primarily to a general year-over-year decline in production at both the SACROC and Yates field units;
- a \$19.3 million (133%) increase due to higher net profits interest revenues from our 28% net profits interest in the Snyder, Texas natural gas processing plant—driven by higher natural gas liquids prices, increased producing volumes in the last half of 2011, and the favorable impact from the restructuring of certain liquids processing contracts that became effective at the beginning of 2011. The contractual changes increased liquids processing production allocated to the plant, and decreased liquids production allocated to the SACROC field unit;
- a \$17.2 million (9%) increase due to higher natural gas plant products sales revenues—due to a 29% increase in our realized weighted average price per barrel of natural gas liquids. The increase in revenues from higher realized sales prices was partially offset, however, by a 15% decrease in liquids sales volumes, mainly related to the contractual reduction in our net interest in liquids production from the SACROC field (described above); and
- a \$30.1 million (10%) decrease due to higher combined operating expenses—driven primarily by higher carbon dioxide supply expenses that related to both initiating carbon dioxide injections into the Katz field and higher carbon dioxide prices.

The increase in earnings before depreciation, depletion and amortization expenses from the segment's sales and transportation activities in 2011 compared to 2010 was attributable to the following:

- a \$43.1 million (21%) increase due to higher carbon dioxide sales revenues—primarily due to higher average sales prices. The segment's average price received for all carbon dioxide sales in 2011 increased 19% compared to 2010, due largely to the fact that a portion of its carbon dioxide sales contracts are indexed to oil prices. In addition, overall carbon dioxide sales volumes increased slightly (1%) in 2011 versus 2010;
- a \$7.5 million (10%) increase due to higher carbon dioxide and crude oil pipeline transportation revenues—due mainly to incremental transportation service on our Eastern Shelf carbon dioxide pipeline. We completed construction of the pipeline in December 2010; and
- a \$16.4 million (30%) decrease due to higher combined operating expenses—driven by higher severance tax expenses and higher carbon dioxide supply expenses, both related to higher commodity prices in 2011.

Year Ended December 31, 2010 versus Year Ended December 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	\$ 114.7	20 %	\$ 160.5	19 %
Sales and Transportation Activities	49.1	23 %	38.0	15 %
Intrasegment Eliminations	-	-	(7.3)	(16)%
Total CO ₂	<u>\$ 163.8</u>	<u>21 %</u>	<u>\$ 191.2</u>	<u>18 %</u>

The segment's overall increase in earnings before depreciation, depletion and amortization expenses in 2010 compared to 2009 was due to higher earnings from both its oil and gas producing activities and its sales and transportation activities. The year-over-year increase in earnings from oil and gas producing activities was due mainly to the following:

- a \$160.5 million (19%) increase due to higher operating revenues—driven by a \$154.4 million (19%) increase in combined crude oil and natural gas plant product sales revenues, due largely to increases of 21% and 34% in our realized weighted average price per barrel of crude oil and natural gas liquids, respectively, and partly to a 5% increase in natural gas liquids sales volumes. The overall increase in sales revenues was somewhat offset by a 5% decline in crude oil sales volumes in 2010; and
- a \$46.8 million (18%) decrease due to higher combined operating expenses—driven by a \$29.7 million (326%) increase in tax expenses, other than income tax expenses, and a \$14.4 million (8%) increase in operating and maintenance expenses. The increase in other tax expenses was primarily due to a \$30.3 million reduction in severance tax expenses in 2009 due to prior year overpayments. The increase in operating expenses was mainly due to higher natural gas processing costs related to both an increase in processing volumes, and higher carbon dioxide purchase costs resulting from higher rates.

Similarly, the \$49.1 million (23%) year-over-year increase in earnings from the segment's sales and transportation activities in 2010 was also largely revenue related, chiefly due to a \$37.5 million (22%) increase in carbon dioxide sales revenues. The increase in carbon dioxide sales revenues was driven by a 22% increase in the average sales price for carbon dioxide. Although our carbon dioxide sales volumes were essentially unchanged across both years, we benefitted from higher average carbon dioxide sales prices in 2010 versus 2009 due to both continued strong customer demand for carbon dioxide's use in oil recovery projects throughout the Permian Basin area and to the positive impact on the portion of our carbon dioxide sales contracts that were tied to crude oil prices, which increased since the end of 2009.

Pipeline revenues from transporting both carbon dioxide and crude oil were essentially flat across 2010 and 2009, and for our CO₂ segment combined, total carbon dioxide delivery volumes decreased almost 3% in 2010 versus 2009. The decrease in delivery volumes was mainly due to lower consumption of new carbon dioxide at both the SACROC and Yates field units. However, carbon dioxide production from our southwest Colorado source fields increased in 2010, and carbon dioxide delivery volumes on our 50%-owned Cortez Pipeline increased by 0.5% in 2010, both reflecting a slight increase in third-party sales compared to 2009.

Our sales and transportation activities also benefitted from a \$5.0 million (123%) decrease in income tax expenses in 2010 versus 2009, primarily due to favorable adjustments to the segment's accrued Texas margin tax liabilities in 2010 due to prior year overpayments.

Terminals

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except operating statistics)		
Revenues	\$ 1,314.6	\$ 1,265.1	\$ 1,109.0
Operating expenses(a)	(634.0)	(629.2)	(536.8)
Other income(b).....	0.9	4.3	27.6
Earnings from equity investments	11.2	1.7	0.7
Interest income and Other, net(c).....	5.5	4.7	3.7
Income tax benefit (expense)(d)	6.3	(5.3)	(5.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 704.5	\$ 641.3	\$ 599.0
Bulk transload tonnage (MMtons)(e).....	100.6	92.5	83.0
Ethanol (MMBbl)	61.0	57.9	32.6
Liquids leaseable capacity (MMBbl).....	60.2	58.2	56.4
Liquids utilization %.....	94.5	96.2	96.6

- (a) 2011 amount includes (i) a \$3.2 million increase in expense from casualty insurance deductibles and the repair of assets related to casualty losses; (ii) a \$2.0 million increase in expense associated with environmental liability adjustments; (iii) a \$0.7 million increase in expense associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009; (iv) a \$0.6 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal; and (v) a \$0.1 million increase in expense associated with the on-going dissolution of our partnership interest in Globalplex Handling. 2010 amount includes (i) a \$6.4 million increase in expense from casualty insurance deductibles and the write-off of assets related to casualty losses; (ii) a \$0.6 million increase in expense related to storm and flood clean-up and repair activities; and (iii) a \$0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition. 2009 amount includes (i) a \$0.9 million increase in expense associated with environmental liability adjustments; (ii) a \$0.7 million increase in expense associated with adjustments to long-term receivables for environmental cost recoveries; (iii) a \$0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal; and (iv) a \$0.3 million decrease in expense related to hurricane clean-up and repair activities.
- (b) 2011 amount includes (i) a \$4.3 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) a \$1.3 million increase in income from the sale of our ownership interest in Arrow Terminals B.V.; (iii) a \$0.1 million increase in income, respectively, from adjustments associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009; (iv) a \$4.4 million decrease in income from the write-off of assets related to casualty losses; and (v) a \$0.4 million decrease in income from property write-offs associated with the on-going dissolution of our partnership interest in Globalplex Handling. 2010 amount includes (i) a \$6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) a combined \$5.5 million decrease in income associated with a write-down of the carrying value of net assets to be sold to their estimated fair values as of December 31, 2010 (associated with the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009); and (iii) a \$1.0 million casualty loss related to the write-off of assets. 2009 amount includes gains of \$24.6 million from hurricane and fire casualty indemnifications.
- (c) 2011 amount includes a combined \$3.6 million gain from the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.
- (d) 2011 amount includes (i) a \$4.8 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense); (ii) a \$1.9 million decrease in expense (reflecting tax savings) related to the net decrease in income from the sale of our ownership interest in the boat fleet business described in both footnotes (a) and (b); (iii) a \$0.2 million decrease in expense (reflecting tax savings) related to the sale of our ownership interest in Arrow Terminals B.V. described in footnote (b); and (iv) a \$1.4 million increase in expense related to the gain associated with the sale of a 51% ownership interest in two of our subsidiaries described in footnote (c). 2010 amount includes a \$1.4 million decrease in expense reflecting the tax effect (savings) on the decrease in income associated with the write-down of the carrying value of net assets to be sold, as described in footnote (b). 2009 amount includes a \$0.9 million increase in expense related to hurricane casualty gains.
- (e) Volumes for acquired terminals are included for all periods.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer,

steel, ores and other dry-bulk material services facilities. We group our bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows our management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

Combined, the certain items described in the footnotes to the table above accounted for an \$8.6 million increase in segment earnings before depreciation, depletion and amortization expenses in 2011 compared to 2010, and a \$28.1 million decrease in earnings before depreciation, depletion and amortization in 2010 compared to 2009. Following is information related to the segment's (i) remaining \$54.6 million (8%) and \$70.4 million (12%) increases in earnings before depreciation, depletion and amortization; and (ii) \$49.5 million (4%) and \$156.1 million (14%) increases in operating revenues in both 2011 and 2010, when compared with the respective prior year:

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA		Revenues		
	increase/(decrease)		increase/(decrease)		
	(In millions, except percentages)				
Mid-Atlantic.....	\$	20.3	53 %	\$ 27.6	30 %
Acquired assets and businesses		15.4	n/a	12.2	n/a
Northeast		9.0	12 %	13.4	10 %
Gulf Liquids		8.4	5 %	20.2	10 %
Midwest.....		4.4	12 %	6.4	7 %
Southeast		3.1	6 %	2.6	2 %
Ohio Valley		(4.1)	(12)%	(1.2)	(2)%
West		(3.7)	(6)%	(6.0)	(5)%
All others (including intrasegment eliminations and unallocated income tax expenses).....		1.8	1 %	(25.7)	(6)%
Total Terminals	\$	54.6	8 %	\$ 49.5	4 %

The increase in earnings from the terminals included in our Mid-Atlantic region was driven by an \$18.1 million increase from our Pier IX terminal, located in Newport News, Virginia. Pier IX benefitted from a \$21.1 million increase in operating revenues that related chiefly to a 5.2 million ton (74%) increase in coal transload volumes. The increase in volumes was due to the ongoing domestic economic recovery, growth in the export market (due to greater foreign demand for both U.S. metallurgical and steam coal), and completed terminal expansions since the end of 2010. Including all terminals, coal volumes handled increased by 20% in 2011 compared to 2010.

During 2011, we acquired certain terminal assets and businesses in order to gain access to new markets and to complement and/or enlarge our existing terminal operations, and combined, these acquired operations contributed incremental earnings before depreciation, depletion and amortization of \$15.4 million and incremental revenues of \$12.2 million in 2011. All of the incremental amounts represent the earnings and revenues from acquired terminals' operations during the additional months of ownership in 2011, and do not include increases or decreases during the same months we owned the assets in 2010. For more information on our terminal acquisitions, see Note 3 to our consolidated financial statements included elsewhere in this report.

The increase in earnings from our Northeast terminals was driven by a \$7.2 million increase from our Carteret, New Jersey liquids terminal, driven by both completed liquids tank expansion projects since the end of 2010 (which increased liquids storage capacity by approximately one million barrels), and higher transfer and storage rates. Including all terminals, we increased our liquids terminals' liquids leasable capacity by 2.0 million barrels (3.4%) during 2011, via both terminal acquisitions and completed terminal expansion projects and, at the same time, our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) at the end of 2011 decreased by only 1.7% since the end of 2010.

The \$8.4 million increase in earnings from our Gulf Liquids terminals primarily related to higher operating results from our two large liquids terminal facilities located along the Houston Ship Channel, driven by higher ethanol volumes, higher distillate warehousing revenues, and new and renewed customer agreements at higher rates. We also benefitted from the March 2011 completion of our Deer Park Rail Terminal and its related ethanol handling assets at our Pasadena terminal. For all of our Gulf Liquids terminals combined, total ethanol handling volumes increased by 86% in 2011 compared to 2010.

The overall increase in earnings from our Midwest terminals was mainly due to higher earnings from the combined operations of our Argo and Chicago, Illinois liquids terminals, due to increased ethanol throughput and incremental

liquids storage and handling business, and to higher contributions from our Dakota Bulk terminal located in St. Paul, Minnesota, due to higher sand and salt transload volumes.

The increase in earnings from our Southeast terminals was due mainly to higher chemical revenues, increased salt handling, and higher storage fees at our Shipyard River Terminal, located in Charleston, South Carolina, and from higher margins from tank blending services involving various agricultural products at our liquids terminal facility located in Wilmington, North Carolina.

Higher overall earnings from our Terminals segment in 2011 versus 2010 were partially offset by lower earnings from terminal operations included in the segment's Ohio Valley and West regions, due mainly to both lower revenues earned from steel handling and iron ore stevedoring services, and lower agricultural exports due to higher soybean meal exports during 2010 as a result of drought conditions in South America.

The remaining increases and decreases in our Terminals segment's earnings and revenues—reported in the “All others” line in the table above—represent increases and decreases in terminal results at various locations; however the decrease in revenues relate largely to terminal assets we sold (or contributed to joint ventures) and no longer consolidate since the end of 2010.

Year Ended December 31, 2010 versus Year Ended December 31, 2009

	EBDA		Revenues			
	increase/(decrease)		increase/(decrease)			
	(In millions, except percentages)					
Acquired assets and businesses	\$	32.2	n/a	\$	59.2	n/a
Gulf Liquids		15.9	11 %		18.5	10 %
West		13.8	28 %		28.1	31 %
Southeast		7.2	17 %		11.1	12 %
Mid-River		5.1	27 %		19.7	34 %
Ohio Valley		4.0	23 %		9.7	17 %
Ethanol		3.6	75 %		4.2	65 %
Lower River (Louisiana)		(6.3)	(13) %		(0.7)	(1) %
All others (including intrasegment eliminations and unallocated income tax expenses)		(5.1)	(2) %		6.3	1 %
Total Terminals	\$	70.4	12 %	\$	156.1	14 %

The overall increase in our Terminals segment's earnings before depreciation, depletion and amortization expenses in 2010 versus 2009 was driven by incremental earnings from the terminal assets and businesses we acquired during 2010. Combined, these acquired operations contributed incremental earnings before depreciation, depletion and amortization of \$32.2 million and revenues of \$59.2 million in 2010. All of the incremental amounts represent the earnings and revenues from acquired terminals' operations during the additional months of ownership in 2010, and do not include increases or decreases during the same months we owned the assets in the prior year.

The earnings increase in 2010 compared to 2009 from our Gulf Liquids terminals was driven by higher liquids warehousing revenues, mainly due to new and incremental customer agreements (at higher rates), and to the completion of various terminal expansion projects that increased liquids tank capacity since the end of 2009. For all liquids terminals combined, we increased our liquids leasable capacity by 1.8 million barrels (3.2%) during 2010 and, at the same time, our overall liquids utilization capacity rate at the end of 2010 decreased by only 0.4% since the prior year-end.

The increase in earnings from our West region terminals was driven by incremental contributions from (i) our Vancouver Wharves bulk marine terminal, located on the north shore of Vancouver, British Columbia, Canada's main harbor; (ii) our Kinder Morgan North 40 terminal, the crude oil tank farm we constructed near Edmonton, Alberta, Canada; (iii) our Washington State terminals located in Vancouver and Longview, Washington; and (iv) our Portland, Oregon bulk terminal. The combined increase in earnings was mainly due to higher transfer volumes of agricultural products and other bulk and liquids commodities, higher rate tonnage, and for our two Canadian terminals, favorable currency translation impacts from a strengthening of the Canadian dollar since the end of 2009.

Earnings from our Southeast, Mid-River, and Ohio Valley terminals, which are located in the Southeast and Central regions of the U.S., also increased in 2010, due largely to increased steel volumes from rebounding steel consumption consistent with the ongoing economic recovery during 2010. For our Terminals segment combined, total steel tonnage increased by 8.0 million tons (48%) in 2010, when compared with the previous year.

The increase in earnings from our Ethanol terminals was driven by incremental services offered by our unit train terminaling facilities located at Richmond and Lomita, California. In March 2010, we began operations at the newly-built Richmond terminal, which is serviced by the Burlington Northern Santa Fe railroad. The increase in earnings from our Lomita rail ethanol terminal was largely due to incremental offloading and distribution volumes, driven by California's growing demand for reformulated fuel blend ethanol. For our Terminals segment combined, ethanol volumes increased by 25.3 million barrels (78%) in 2010, primarily due to the growth in demand from the state of California and to the incremental handling activities from the terminal assets we acquired from US Development Group LLC in January 2010.

For 2010, earnings from our Lower River (Louisiana) terminal operations decreased compared to the prior year. The decrease was primarily due to lower earnings from both our International Marine Terminals (IMT) facility, a multi-product, import-export facility located in Port Sulphur, Louisiana and owned 66 2/3% by us, and our Westwego, Louisiana liquids terminal. The decrease in IMT's earnings was due to both a general loss in business in 2010, and a \$3.2 million property casualty gain, recognized in 2009, on a vessel dock that was damaged in March 2008. In September 2010, IMT experienced a catastrophic failure of its shiploader, which negatively impacted its ability to load vessels. The decrease in earnings from our Westwego facility was primarily due to lower revenues resulting from a drop in petroleum fuel storage.

Kinder Morgan Canada

	Year Ended December 31,		
	2011	2010	2009
	(In millions, except operating statistics)		
Revenues	\$ 302.4	\$ 268.5	\$ 226.1
Operating expenses.....	(97.7)	(91.6)	(72.5)
Earnings from equity investments	(2.0)	(3.3)	(4.1)
Interest income and Other, net.....	13.8	15.8	23.9
Income tax benefit (expense)(a).....	(14.9)	(7.8)	(18.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	<u>\$ 201.6</u>	<u>\$ 181.6</u>	<u>\$ 154.5</u>
Transport volumes (MMBbl)(b)	<u>99.9</u>	<u>108.4</u>	<u>102.5</u>

(a) 2011 amount includes a \$3.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts or realize any direct benefits related to this compensation expense). 2009 amount includes a \$14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to Trans Mountain's carrying amount of the previously established deferred tax liability, and a \$3.7 million decrease in expense due to a certain non-cash accounting adjustment related to book tax accruals made by the Express pipeline system.

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and our one-third ownership interest in the Express crude oil pipeline system. The certain items relating to "Income tax benefit (expense)" described in footnote (a) to the table above accounted for increases in segment earnings before depreciation, depletion and amortization expenses of \$3.1 million in 2011 and \$11.2 million in 2010, when compared with the respective prior year.

Following is information related to the segment's (i) remaining \$16.9 million (9%) and \$15.9 million (10%) increases in earnings before depreciation, depletion and amortization; and (ii) \$33.9 million (13%) and \$42.4 million (19%) increases in operating revenues in both 2011 and 2010, when compared with the respective prior year:

Year Ended December 31, 2011 versus Year Ended December 31, 2010

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	\$	20.5	13 %	\$ 33.7 13 %
Express Pipeline		(3.8)	(26)%	- -
Jet Fuel Pipeline		0.2	7 %	0.2 4 %
Total Kinder Morgan Canada	\$	16.9	9 %	\$ 33.9 13 %

The overall increase in Trans Mountain's earnings before depreciation, depletion and amortization expenses in 2011 compared to 2010 included an increase of \$4.4 million due to favorable currency impacts, primarily related to favorable changes from the translation of earnings.

Trans Mountain's remaining \$16.1 million year-over-year increase in earnings before depreciation, depletion and amortization was driven by higher operating revenues, primarily due to favorable impacts from a negotiated pipeline toll settlement agreement which became effective on January 1, 2011. The one-year negotiated toll agreement was formally approved by the National Energy Board (Canada) on April 29, 2011, and replaced the previous mainline toll settlement agreement that expired on December 31, 2010.

The decrease in earnings from our investment in the Express pipeline system was driven by a \$5.4 million increase in income tax expenses, due to a drop in income tax expense in 2010 related to a valuation allowance release on previously established deferred tax balances. The overall decrease in earnings was partially offset by a \$1.2 million increase in equity earnings, primarily due to higher domestic transportation volumes on the Platte Pipeline segment.

Year Ended December 31, 2010 versus Year Ended December 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	\$	9.8 6 %	\$	41.1 19 %
Express Pipeline		7.3 96 %		- -
Jet Fuel Pipeline		(1.2) (25) %		1.3 31 %
Total Kinder Morgan Canada	\$	15.9 10 %	\$	42.4 19 %

The increase in our Kinder Morgan Canada business segment's earnings before depreciation, depletion and amortization expenses in 2010 compared to 2009 was driven by higher earnings from our Trans Mountain pipeline system and our investment in the Express pipeline system. The overall \$9.8 million (6%) increase in Trans Mountain's earnings in 2010 consisted of a \$22.8 million (15%) increase due to higher operating income (revenues less operating expenses), and a combined \$13.0 million (373%) decrease due to both lower income from foreign currency transactions (included in non-operating other income) and higher income tax expenses.

The increase in operating income (and related income tax expenses) was driven by higher crude oil volumes moving across Trans Mountain's marine dock located in Port Metro Vancouver (system throughput volumes increased by 6% overall compared to 2009). The decrease in income from foreign currency transactions was primarily attributable to lower currency gains on Trans Mountain's outstanding, short-term, intercompany interest obligations payable in U.S. dollars. Although the Canadian dollar did strengthen during 2010, gains from the revaluation of U.S.-based interest liabilities were lower in 2010 because the impact was not as favorable as in 2009.

The overall increase in earnings from our investment in the Express pipeline system included a \$5.5 million increase due to lower year-over-year income tax expenses in 2010, and a \$1.2 million increase due to higher interest income earned from our long-term debt investment in Express. The drop in income tax expenses in 2010 compared to 2009 was driven by the valuation allowance release on deferred tax balances described above, and the increase in interest income was due to favorable currency translation impacts in 2010.

Other

	Year Ended December 31,		
	2011	2010	2009
		(In millions)	
General and administrative expenses(a)	\$ 472.7	\$ 375.2	\$ 330.3
Interest expense, net of unallocable interest income(b)	\$ 531.0	\$ 506.4	\$ 431.3
Unallocable income tax expense.....	\$ 8.7	\$ 9.9	\$ 8.5
Net income attributable to noncontrolling interests(c).....	\$ 10.6	\$ 10.8	\$ 16.3

- (a) 2011 amount includes (i) a combined \$89.9 million increase in non-cash compensation expense (including \$87.1 million related to a special non-cash bonus expense to non-senior management employees) allocated to us from KMI; however, we do not have any obligation, nor did we pay any amounts related to this expense; (ii) a combined \$4.1 million increase in expense for unallocated legal expenses and certain asset and business acquisition expenses; and (iii) a \$0.2 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount includes (i) a \$4.6 million increase in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor did we pay any amounts related to this expense); (ii) a \$4.2 million increase in expense for certain asset and business acquisition costs; (iii) a \$1.6 million increase in legal expense associated with items disclosed in these footnotes such as legal settlements and pipeline failures; and (iv) a \$0.2 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2009 amount includes (i) a \$5.7 million increase in non-cash compensation expense, allocated to us from KMI (we do not have any obligation, nor did we pay any amounts related to this expense); (ii) a \$2.3 million increase in expense for certain asset and business acquisition costs, which under prior accounting standards would have been capitalized; (iii) a \$1.3 million increase in expense for certain land transfer taxes associated with our April 30, 2007 Trans Mountain acquisition; and (iv) a \$2.7 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
- (b) 2011, 2010 and 2009 amounts include increases in imputed interest expense of \$0.7 million, \$1.1 million and \$1.6 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
- (c) 2011, 2010 and 2009 amounts include decreases of \$6.6 million, \$4.6 million and \$0.7 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2011, 2010 and 2009 items previously disclosed in the footnotes to the tables included in “—Results of Operations.”

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

Combined, the certain items described in footnote (a) to the table above increased our general and administrative expenses by \$83.6 million in 2011 and \$3.6 million in 2010, when compared with the respective prior year. The remaining \$13.9 million (4%) increase in general and administrative expenses in 2011 compared to 2010 was driven by (i) a combined \$10.8 million increase due to higher employee benefits and payroll tax expenses (due mainly to both cost inflation increases on work-based health and insurance benefits and higher wage rates); (ii) higher overall salary and labor expenses; and (iii) higher environmental and pension expenses related to our Canadian pipeline operations.

For 2010 compared to 2009, the remaining \$41.3 million (13%) increase in expenses included increases of (i) \$21.9 million from higher employee benefit and payroll tax expenses; (ii) \$5.7 million from higher overall corporate insurance expenses; and (iii) \$5.2 million from higher unallocated legal expenses. The increase in benefit and payroll tax expenses was mainly due to the overall variability in year-over-year health and medical costs, higher wage rates and a larger year-over-year labor force. The increase in insurance expenses was primarily due to higher expense accruals in 2010, related mainly to year-over-year increases in commercial property and liability insurance costs, and partly to incremental premium taxes. The increase in legal expenses was primarily due to higher outside legal services.

In the table above, we report our interest expense as “net,” meaning that we have subtracted unallocated interest income and capitalized interest from our interest expense to arrive at one interest amount, and after taking into effect the certain items described in footnote (b) to the table above, our unallocable interest expense increased \$25.0 million (5%) in

2011 compared to 2010, and increased \$75.6 million (18%) in 2010 compared to 2009. For both pairs of comparable years, the increase in interest expense was attributable to higher average borrowings.

Our average debt balances increased 10% in 2011 and 16% in 2010, when compared to the respective prior year. The increases in average borrowings were largely due to the capital expenditures, external business acquisitions, and investment contributions we have made since the beginning of 2009. For more information on our capital expenditures, capital contributions, and acquisition expenditures, see “—Liquidity and Capital Resources.”

The weighted average interest rate on all of our borrowings—including both short-term and long-term amounts—decreased by 2% in 2011, and by 5% in 2010, when compared with the respective prior year (the weighted average interest rate on all of our borrowings was 4.26% during 2011, 4.35% during 2010 and 4.57% during 2009). The decreases were due primarily to a general drop in variable interest rates since the beginning of 2009, including decreases in the variable interest rate we paid on the borrowings made under our revolving bank credit facility, and in 2011 and 2010, under our commercial paper program.

We use interest rate swap agreements to transform 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, and as of both December 31, 2011 and 2010, approximately 47% of our consolidated debt balances (excluding the value of interest rate swap agreements) was 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 13 to our consolidated financial statements included elsewhere in this report.

Unallocable income tax expenses relate to corporate income tax accruals for the Texas margin tax, an entity-level tax imposed on the amount of our total revenue that is apportioned to the state of Texas. Both the increase in expense, in 2010, and the decrease in expense, in 2011, was due to higher margin tax expense accruals in 2010, relative to both 2011 and 2009.

Net income attributable to noncontrolling interests, which represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our operating limited partnerships and their consolidated subsidiaries that are not held by us, was essentially unchanged across both 2011 and 2010. The decrease in 2010 compared to 2009 was chiefly due to the higher net income allocated to the 33 1/3% noncontrolling interest in the International Marine Terminals facility in 2009, discussed above in “—Terminals.”

Liquidity and Capital Resources

General

As of December 31, 2011, we had \$409.3 million of “Cash and cash equivalents” on our consolidated balance sheet (included elsewhere in this report), an increase of \$280.2 million from December 31, 2010. We also had, as of December 31, 2011, approximately \$1.3 billion of borrowing capacity available under our \$2.2 billion senior unsecured revolving credit facility (discussed below in “—Short-term Liquidity”). We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash (which may result from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings (including commercial paper issuances), and the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;
- interest payments with cash flows from operating activities; and

- debt principal payments, as such debt principal payments become due, with additional borrowings or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in “—Financing Activities.”

Credit Ratings and Capital Market Liquidity

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and expansion activities in order to maintain acceptable financial ratios. The major debt rating agencies routinely evaluate our outstanding debt, and our cost of borrowing can increase or decrease depending on these debt ratings. Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (negative) and BBB (stable), at Standard & Poor’s Ratings Services, Moody’s Investors Service, Inc. and Fitch, Inc., respectively. On October 18, 2011, in response to KMI’s announcement that it has reached an agreement to purchase 100% of the outstanding stock of El Paso Corporation, Moody’s revised its outlook on our long-term credit rating to negative from stable. The rating agency’s revision reflected its view that the increased leverage at KMI associated with this acquisition will put additional strain on us to upstream cash to KMI. Further information about this announcement is described in Note 1 to our consolidated financial statements included elsewhere in this report.

Our short-term corporate debt credit rating is A-2 (susceptible to adverse economic conditions, however, capacity to meet financial commitments is satisfactory), Prime-2 (strong ability to repay short-term debt obligations) and F2 (good quality grade with satisfactory capacity to meet financial commitments), at Standard & Poor’s Ratings Services, Moody’s Investors Service, Inc. and Fitch, Inc., respectively. Based on these credit ratings, we expect that our short-term liquidity needs will be met primarily through borrowings under our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy pipeline and terminals industries and other financial and business factors, some of which are beyond our control.

Additionally, some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. These financial problems may arise from current global economic conditions, changes in commodity prices or otherwise. We have been and are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these customers. We cannot provide assurance that one or more of our current or future financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows; however, we have no material concentrations of credit risk and we believe we have provided adequate allowance for such customers.

Short-term Liquidity

As of December 31, 2011, our principal sources of short-term liquidity were (i) our \$2.2 billion five-year senior unsecured revolving credit facility with a diverse syndicate of banks that matures July 1, 2016; (ii) our \$2.2 billion short-term commercial paper program (which is supported by our revolving credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings and letters of credit); and (iii) cash from operations. The loan commitments under our revolving credit facility can be used to fund borrowings for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings of up to \$2.5 billion.

As of December 31, 2011, our credit facility was not drawn on, and as discussed above in “—General,” we provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our credit facility. After reduction for (i) our outstanding borrowings under our commercial paper program; and (ii) our outstanding letters of credit, the remaining available borrowing capacity under our credit facility was \$1,324.9 million as of December 31, 2011. Additionally, we have consistently generated strong cash flow from operations, providing a source of funds of \$2,873.8 million in 2011 and \$2,416.8 million in 2010 (the year-to-year increase is discussed below in “—Operating Activities”).

Our outstanding short-term debt as of December 31, 2011 was \$1,637.8 million, primarily consisting of (i) \$644.8 million of commercial paper borrowings (due in part to our short-term credit rating upgrade in February 2011, we made no short-term borrowings under our revolving credit facility in 2011, but instead made borrowings under our commercial paper program); (ii) \$450.0 million in principal amount of 7.125% senior notes that mature March 15, 2012; and (iii)

\$500.0 million in principal amount of 5.85% senior notes that mature September 15, 2012. We intend to refinance our current short-term debt through a combination of long-term debt, equity, and/or the issuance of additional commercial paper or credit facility borrowings to replace maturing commercial paper and current maturities of long-term debt.

We had working capital deficits of \$1,543.7 million as of December 31, 2011 and \$1,477.5 million as of December 31, 2010. The \$66.2 million (4%) unfavorable change from year-end 2010 was primarily due to a \$375.4 million increase in short-term debt, partially offset by the \$280.2 million increase in “Cash and cash equivalents” discussed above in “—General.” The overall increase in short-term debt was mainly due to the following: (i) a \$250.0 million net increase in the current maturities of long-term debt; and (ii) a \$122.7 million increase due to higher net commercial paper borrowings.

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 cash and cash equivalent balances as a result of debt or equity issuances (discussed below in “—Long-term Financing”). Although working capital can be considered a measure of a company’s ability to meet its short-term cash needs, a working capital deficit is not unusual for us or for other companies similar in size and scope to us. Furthermore, we believe that our working capital deficit does not indicate a lack of liquidity as we continue to maintain adequate current assets and committed lines of credit to satisfy current liabilities and maturing obligations when they come due.

We employ a centralized cash management program for our U.S.-based bank accounts that essentially concentrates the cash assets of our operating partnerships and their subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. Our centralized cash management program provides that funds in excess of the daily needs of our operating partnerships and their subsidiaries are concentrated, consolidated, or otherwise made available for use by other entities within our 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 parent companies other than restrictions that may be contained in agreements governing the indebtedness of those entities. However, our cash and the cash of our subsidiaries is not concentrated into accounts of KMI or any company not in our consolidated group of companies, and KMI has no rights with respect to our cash except as permitted pursuant to our partnership agreement.

Furthermore, certain of our operating 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

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions of cash from operations to our common unitholders, Class B unitholder and general partner) through issuing long-term notes or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

Our equity offerings consist of the issuance of additional common units or the issuance of additional i-units to KMR (which KMR purchases with the proceeds from the sale of additional KMR shares). As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR’s purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors. For more information on our 2011 and 2010 equity issuances, including cash proceeds received from both public offerings of common units and our equity distribution agreement, see Note 10 to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. Our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate senior notes provide that we may redeem the notes 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. For additional information on our debt securities and on our 2011 and 2010 debt

related transactions, including our issuances of senior notes, see Note 8 to our consolidated financial statements included elsewhere in this report.

As of December 31, 2011 and December 31, 2010, the net carrying value of the various series of our senior notes was \$12,026.0 million and \$10,876.7 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was \$126.5 million and \$141.0 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives.

We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term senior notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See “— Credit Ratings and Capital Market Liquidity” above for a discussion of our credit ratings.

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, financing our expansion capital expenditures and acquisitions with approximately 50% equity and 50% debt. In the short-term, we fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable interest rates. 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.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset, and for the year ended December 31, 2011, our sustaining capital expenditures totaled \$212.1 million. This amount included \$9.9 million for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) Fayetteville Express Pipeline LLC; (iv) Cypress Interstate Pipeline LLC; (v) EagleHawk Field Services LLC; (vi) Red Cedar Gathering Company; and (vii) for the first six months of 2011 only, KinderHawk Field Services LLC (effective July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk that we did not already own and we subsequently included its sustaining capital expenditures in our consolidated totals).

For the year ended December 31, 2010, our sustaining capital expenditures totaled \$179.2 million. This amount included \$0.2 million for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) KinderHawk Field Services LLC; (iv) Cypress Interstate Pipeline LLC; and (v) Fayetteville Express Pipeline LLC.

Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Rockies Express, Midcontinent Express and Fayetteville Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, with proceeds from issuing their own long-term notes, or with proceeds from contributions received from their member owners. We have no contingent debt obligations with respect to Rockies Express, Midcontinent Express, or Fayetteville Express. For information on our contingent debt obligations, see Note 12 to our consolidated financial statements included elsewhere in this report. We have forecasted \$248.7 million for sustaining capital expenditures in our 2012 budget. This amount includes \$11.5 million for our proportionate share of our equity investors' sustaining capital expenditures.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. Our discretionary capital expenditures totaled \$997.3 million in 2011 and \$821.9 million in 2010. The year-to-year increase in discretionary capital expenditures was primarily due to higher investment undertaken in 2011 to expand and improve our Products Pipelines and CO₂ business segments. Generally, we initially fund our discretionary capital expenditures through borrowings under our revolving credit facility or our commercial paper program until the amount

borrowed is of a sufficient size to cost effectively offer either debt, equity, or both. We have forecasted \$1,323.0 million for discretionary capital expenditures in our 2012 budget. This amount does not include forecasted discretionary expenditures by our equity investees, forecasted capital contributions to our equity investees, or forecasted expenditures for asset acquisitions.

Capital Contributions

In addition to our discretionary capital expenditures, we contributed a combined \$371.0 million to our equity investees in 2011. Our 2011 contributions included payments of \$195.0 million to our 50%-owned Fayetteville Express Pipeline LLC and combined payments of \$135.5 million to our two equity investees that gather natural gas located in the Eagle Ford shale formation in South Texas (our 50%-owned Eagle Ford Gathering LLC and our 25%-owned EagleHawk Field Services LLC). Fayetteville Express used the contributions to repay borrowings under its previous \$1.1 billion bank credit facility, and subsequently, entered into new borrowing facilities. Both Eagle Ford Gathering and EagleHawk Field Services used our contributions as partial funding for natural gas gathering infrastructure expansions.

In 2010, we made equity investment contributions of \$299.3 million. Our 2010 contributions primarily consisted of a combined \$216.5 million contributed to Rockies Express Pipeline LLC and Midcontinent Express Pipeline LLC to partially fund our respective share of Rockies Express and Midcontinent Express natural gas pipeline system construction costs. Fayetteville Express funded its 2010 natural gas pipeline construction costs with borrowings under its own \$1.1 billion, unsecured revolving bank credit facility.

Generally, we fund our equity investment contributions through borrowings under our commercial paper program or our bank credit facility. To the extent these sources of funding are not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash.

Capital Requirements for Recent Transactions

For each of the years ended December 31, 2011 and 2010, our net cash outlays for the acquisition of assets and investments totaled \$1,178.7 million and \$1,213.2 million, respectively. Our cash payments for acquired assets and investments in 2011 included (i) \$835.1 million for both our remaining 50% ownership interest in KinderHawk Field Services LLC and our 25% interest in EagleHawk Field Services LLC; (ii) \$151.5 million for natural gas treating assets acquired from SouthTex Treaters, Inc.; (iii) \$100.0 million for a preferred equity interest in Watco Companies, LLC; and (iv) \$42.9 million for terminal assets acquired from TGS Development, L.P. (we also issued common units valued at \$23.7 million as consideration). Our 2010 cash outlays for strategic business acquisitions primarily consisted of (i) \$921.4 million for our initial 50% ownership interest in KinderHawk; (ii) \$114.3 million for three unit train ethanol handling terminals acquired from US Development Group LLC (we also issued common units valued at \$81.7 million as consideration); and (iii) \$97.0 million for terminal assets and investments acquired from Slay Industries.

With the exception of the terminal assets which were partially acquired by the issuance of additional common units, we utilized our commercial paper program to fund our 2011 and 2010 acquisitions and then reduced our short-term borrowings with the proceeds from our 2011 and 2010 equity and long-term senior notes issuances. All of our significant 2011 and 2010 acquisitions are discussed further in Note 3 to our consolidated financial statements included elsewhere in this report.

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 12 to our consolidated financial statements included elsewhere in this report. Additional information regarding the nature and business purpose of our investments is included in Note 6 to our consolidated financial statements included elsewhere in this report.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	1-3 years (In millions)	3-5 years	More than 5 years
Contractual Obligations:					
Debt borrowings-principal payments.....	\$ 12,821.3	\$ 1,638.0	\$ 1,010.2	\$ 800.0	\$ 9,373.1
Interest payments(a).....	10,896.2	715.8	1,346.2	1,226.1	7,608.1
Lease obligations(b).....	232.8	51.6	71.1	45.6	64.5
Pension and postretirement welfare plans(c).....	89.4	6.6	14.6	16.6	51.6
Other obligations(d).....	12.5	8.8	2.2	0.6	0.9
Total.....	<u>\$ 24,052.2</u>	<u>\$ 2,420.8</u>	<u>\$ 2,444.3</u>	<u>\$ 2,088.9</u>	<u>\$ 17,098.2</u>
Other commercial commitments:					
Standby letters of credit(e).....	<u>\$ 295.1</u>	<u>\$ 295.1</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
Capital expenditures(f).....	<u>\$ 286.1</u>	<u>\$ 286.1</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>

- (a) Interest payment obligations exclude adjustments for interest rate swap agreements.
- (b) Represents commitments pursuant to the terms of operating lease agreements.
- (c) Represents expected benefit payments from pension and postretirement welfare plans as of December 31, 2011.
- (d) For the Less than 1 year column, represents (i) \$7.5 million due pursuant to our purchase and sale agreement with TGS Development L.P. for the acquisition of certain petroleum coke terminal assets effective June 10, 2011; and (ii) \$1.3 million due pursuant to our purchase and sale agreement with Gas-Chill, Inc. for the acquisition of certain natural gas treating assets effective September 1, 2010. For the remaining columns, represents amounts due pursuant to our purchase and sale agreement with Slay Industries for the acquisition of certain bulk and liquid terminal assets effective March 5, 2010.
- (e) The \$295.1 million in letters of credit outstanding as of December 31, 2011 consisted of the following: (i) a \$100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) our \$30.3 million guarantee under letters of credit totaling \$45.5 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (iii) a \$39.4 million letter of credit supporting our pipeline and terminal operations in Canada; (iv) a \$25.4 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (v) a \$24.1 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (vi) a \$16.7 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; (vii) a \$16.2 million letter of credit supporting debt securities issued by the Express pipeline system; (viii) a \$10.7 million letter of credit supporting our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (ix) a combined \$17.1 million in eight letters of credit supporting environmental and other obligations of us and our subsidiaries.
- (f) Represents commitments for the purchase of plant, property and equipment as of December 31, 2011.

Operating Activities

Net cash provided by operating activities was \$2,873.8 million in 2011, versus \$2,416.8 million in 2010. The overall year-to-year increase of \$457.0 million (19%) in cash flows from operations primarily consisted of:

- a \$236.2 million increase in cash from overall higher partnership income—after adjusting our period-to-period \$58.7 million decrease in net income for the following five non-cash items: (i) a \$167.2 million increase relating to the non-cash loss from the remeasurement of our previous 50% equity interest in KinderHawk Field Services LLC (as discussed in Note 3 to our consolidated financial statements included elsewhere in this report); (ii) an \$85.3 million increase due to certain higher non-cash compensation expenses allocated to us from KMI (as discussed in Note 11 to our consolidated financial statements included elsewhere in this report, we do not have any obligation, nor did we pay any amounts related to these allocated expenses); (iii) a \$79.8 million increase from adjustments made to our rate case and other legal liabilities; (iv) a \$50.6 million increase due to higher non-cash depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); and (v) an

\$88.0 million decrease due to higher earnings from equity investees. The period-to-period change in partnership income in 2011 versus 2010 is discussed above in “—Results of Operations” (including all of the certain items disclosed in the associated table footnotes);

- a \$139.9 million increase in cash related to net changes in both non-current assets and liabilities and other non-cash income and expense items, primarily driven by (i) a \$164.3 million increase in cash due to higher net dock premiums and toll collections received from our Trans Mountain pipeline system customers; and (ii) a net \$25.4 million decrease in cash attributable to lower non-cash earnings adjustments in 2011, including, among other items, amortization of debt-related discounts and premiums, income from the sale or casualty of net assets, and deferred tax expenses;
- a \$124.9 million increase in cash attributable to lower payments made in 2011 to various shippers on our Pacific operations’ refined products pipelines. In 2011 and 2010, we paid legal settlements of \$81.4 million and \$206.3 million, respectively, to settle various interstate and California intrastate transportation rate challenges filed by shippers with the FERC and the CPUC, respectively, dating back as early as 1992;
- a \$66.8 million increase in cash from higher distributions of earnings from equity investees. The increase was chiefly due to incremental distributions from our interests in Fayetteville Express Pipeline LLC, Eagle Ford Gathering LLC, EagleHawk Field Services LLC, and for the periods prior to our July 1, 2011 acquisition of the remaining 50% interest, KinderHawk Field Services, LLC; and
- an \$84.6 million decrease in cash from interest rate swap termination payments. In 2011 and 2010, we received proceeds of \$73.0 million and \$157.6 million, respectively, from the early termination of various fixed-to-variable interest rate swap agreements.

Investing Activities

Net cash used in investing activities was \$2,416.9 million for the year ended December 31, 2011, compared to \$2,311.6 million for the prior year. The year-to-year \$105.3 million (5%) decrease in cash due to higher cash expended for investing activities was primarily attributable to the following:

- a \$198.6 million decrease in cash due to higher capital expenditures, as described above in “—Capital Expenditures;”
- a \$71.7 million decrease in cash due to higher contributions to equity investees, as described above in “—Capital Contributions;”
- an \$89.9 million increase in cash from higher proceeds received for combined margin and restricted deposits, primarily related to a \$50.0 million increase due to the 2011 release of restricted cash. As of December 31, 2010, we placed \$50.0 million in a cash escrow account and we reported this amount as “Restricted deposits” on our year-end balance sheet. We paid this amount in January 2011 for our initial equity investment in Watco Companies, LLC;
- a \$34.5 million increase in cash due to lower acquisitions of assets and investments, as described above in “—Capital Requirements for Recent Transactions;” and
- a \$28.7 million increase in cash due to higher repayments received in 2011 on a related party loan we made in July 2004 to Plantation Pipe Line Company; and
- a \$24.9 million increase in cash due to higher capital distributions (distributions in excess of cumulative earnings) received from equity investments in 2011—chiefly due to \$21.8 million of incremental capital distributions received from Fayetteville Express Pipeline LLC.

Financing Activities

We used net cash of \$169.1 million and \$125.0 million, respectively, in financing activities in 2011 and 2010. The \$44.1 million (35%) overall decrease in cash from our financing activities in 2011 versus 2010 was mainly due to:

- a \$417.0 million decrease in cash due to higher partnership distributions. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our noncontrolling interests, totaled \$2,243.6 million

in 2011, versus \$1,826.6 million in 2010. For further information regarding our 2011 and 2010 partnership distributions, see Notes 10 and 11 to our consolidated financial statements included elsewhere in this report;

- a \$196.6 million increase in cash due to higher partnership equity issuances. The increase reflects the \$955.3 million we received, after commissions and underwriting expenses, from the sales of additional common units in 2011, versus the \$758.7 million we received from the sales of additional common units in 2010. All of our 2011 and 2010 equity issuances are discussed in Note 10 to our consolidated financial statements included elsewhere in this report; and
- a \$159.7 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The overall increase in cash was primarily due to (i) a \$392.9 million increase due to higher net issuances of our senior notes; (ii) a \$154.0 million decrease due to the repayment of all of the outstanding borrowings under KinderHawk Field Services LLC’s bank credit facility that we assumed on our July 1, 2011 acquisition date; and (iii) a \$99.4 million decrease due to lower net short-term borrowings (consisting of borrowings and repayments under both our commercial paper program and our revolving credit facility). For more information about our debt financing activities, see Note 8 to our consolidated financial statements included elsewhere in this report.

Recent Accounting Pronouncements

Please refer to Note 18 to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

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,” “position,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions 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 of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal, steel and other bulk materials and chemicals 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 implemented by the Federal Energy Regulatory Commission, California Public Utilities Commission, Canada’s National Energy Board or another regulatory agency;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical 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 from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains, areas of shale gas formation and the Alberta oil sands;

- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting standards 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;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through 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, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, accidents, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and 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 workovers, and in drilling new wells;
- the uncertainty inherent in estimating future oil and natural gas production or reserves that we may experience;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 16 to our consolidated financial statements included elsewhere in this report.

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 of the forward-looking statements will occur, or if any of them do, 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.

See Item 1A “Risk Factors” for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in Item 1A “Risk Factors.” The risk 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, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

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, such as weather-related risk, in the ordinary course of business. However, we take steps to hedge, or limit our exposure to, these risks in order to maintain a more stable and predictable earnings stream. Stated another way, we execute 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, natural gas liquids and crude oil. The derivative contracts we use include energy products traded on the New York Mercantile Exchange and over-the-counter markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps.

Fundamentally, our hedging strategy involves taking a simultaneous position in the futures market that is equal and opposite to our position, or anticipated position, in the cash market (or physical product) 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 directly offsetting any change in prices, either positive or negative. A hedge is successful when gains or losses in the cash market are neutralized by losses or gains in the futures transaction.

Our policies require that we only enter into derivative contracts 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 we enter into derivative transactions only 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 Ratings Services):

	<u>Credit Rating</u>
J. Aron & Company / Goldman Sachs	A-
Barclays.....	A+
Credit Suisse	A

As discussed above, our 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, natural gas liquids and crude oil. Using derivative contracts for this purpose helps provide us increased certainty with regard to our operating cash flows and helps us undertake further capital improvement projects, attain budget results and meet distribution targets to our partners. We categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but whose value is uncertain. Cash flow hedges are defined as hedges made with the intention of decreasing the variability in cash flows related to future transactions, as opposed to the value of an asset, liability or firm commitment, and we are allowed special hedge accounting treatment for such derivative contracts.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income (loss), outside “Net Income” reported in our consolidated statements of income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts’ gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included within “Accumulated other comprehensive income (loss)” in our accompanying consolidated balance sheets but not included in our net income (portions attributable to our noncontrolling

interests are included within “Noncontrolling interests” and are not included in our net income). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

All remaining gains and losses on the derivative contracts (the ineffective portion) are included in current net income. The ineffective portion of the gain or loss on the derivative contracts is the difference between the gain or loss from the change in value of the derivative contract and the effective portion of that gain or loss. In addition, when the hedged forecasted transaction does take place and affects earnings, the effective part of the hedge is also recognized in the income statement, and the earlier recognized effective amounts are removed from “Accumulated other comprehensive income (loss)” (and “Noncontrolling interests”) and are transferred to the income statement as well, effectively offsetting the changes in cash flows stemming from the hedged risk. If the forecasted transaction results in an asset or liability, amounts should be reclassified into earnings when the asset or liability affects earnings through cost of sales, depreciation, interest expense, etc. For more information on our other comprehensive income (loss) and our “Accumulated other comprehensive income (loss),” see Notes 2 and 13 to our consolidated financial statements included elsewhere in this report.

We measure the risk of price changes in the natural gas, natural gas liquids and crude oil markets utilizing a value-at-risk model. Value-at-risk is a statistical measure estimating the probability of portfolio losses over a given holding period, within a certain level of statistical confidence. We utilize a closed form model to evaluate risk on a quarterly basis. Our value-at-risk computations utilize a confidence level of 97.7% for the resultant price movement, and we choose a holding period of one day for the calculation. The confidence level used means that there is a 97.7% probability that the mark-to-market losses for a single day will not exceed the value-at-risk number presented. For each of the years ended December 31, 2011 and 2010, our value-at-risk reached a high of \$9.4 million and \$6.9 million, respectively, and a low of \$3.0 million and \$2.5 million, respectively. Value-at-risk as of December 31, 2011 was \$3.0 million, and averaged \$6.8 million for 2011. Value-at-risk as of December 31, 2010 was \$2.5 million, and averaged \$4.6 million for 2010.

Our calculated value-at-risk exposure represents an estimate of the reasonably possible net losses that would be recognized on our combined portfolio of derivative contracts (including commodity futures and options contracts, fixed price swaps, basis swaps and over-the-counter options) and corresponding physical commodities 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.

In addition, as discussed above, we enter into our derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore both in the value-at-risk calculation and in reality, the change in the market value of our derivative contracts portfolio is offset largely by changes in the value of the underlying physical transactions. For more information on our energy commodity risk management activities, see Note 13 to our consolidated financial statements included elsewhere in this report.

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, we do not have an obligation to prepay fixed rate debt prior to maturity and, as a result, interest rate risk and changes in fair value should not have a significant impact on our fixed rate debt until we would be required to refinance such debt.

As of December 31, 2011 and 2010, the carrying values of our fixed rate debt were \$12,063.8 million and \$10,929.0 million, respectively. These amounts compare to, as of December 31, 2011 and 2010, fair values of \$13,504.0 million and \$11,832.6 million, respectively. Fair values were determined using quoted market prices, where applicable, or future cash flow discounted at market rates for similar types of borrowing arrangements. A hypothetical 10% change in the average interest rates applicable to such debt for 2011 and 2010, would result in changes of approximately \$525.8 million and \$466.4 million, respectively, in the fair values of these instruments. The carrying value and fair value of our variable rate debt, including associated accrued interest and excluding the value of interest rate swap agreements (discussed following), was \$733.7 million as of December 31, 2011 and \$611.1 million as of December 31, 2010.

As of December 31, 2011 and 2010, we were a party to interest rate swap agreements with notional principal amounts of \$5.3 billion and \$4.8 billion, respectively. An interest rate swap agreement is a contractual agreement entered into between two counterparties under which each agrees to make periodic interest payments to the other for an agreed period of time based upon a predetermined amount of principal, which is called the notional principal amount. Normally at each payment or settlement date, the party who owes more pays the net amount; so at any given settlement date only one party actually makes a payment. The principal amount is notional because there is no need to exchange actual amounts of principal. A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 43 basis points in 2011 and 43 basis points in 2010), when applied to our outstanding balance of variable rate debt as of December 31, 2011 and 2010, including adjustments for the notional swap amounts described above, would result in changes of approximately \$25.8 million and \$23.4 million, respectively, in our 2011 and 2010 annual pre-tax earnings.

We entered into our interest rate swap agreements for the purpose of transforming a portion of the underlying cash flows related to our 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 our fixed rate debt varies with changes in the market rate of interest, we enter into swap agreements 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 our fixed rate debt due to market rate changes.

As of both December 31, 2011 and 2010, all of our interest rate swap agreements represented fixed-for-variable rate swaps, where we agreed to pay our counterparties a variable rate of interest on a notional principal amount, comprised of principal amounts from various series of our long-term fixed rate senior notes. In exchange, our counterparties agreed to pay us a fixed rate of interest, thereby allowing us to transform our fixed rate liabilities into variable rate obligations without the incurrence of additional loan origination or conversion costs.

We monitor our 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 balances outstanding under our variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. In general, we attempt to maintain an overall target mix of approximately 50% fixed rate debt and 50% variable rate debt.

As of both December 31, 2011 and 2010, our cash and investment portfolio included \$8.2 million in fixed-income debt securities. These amounts are included within "Investments" in our accompanying consolidated balance sheets at each reporting date and are not material to our consolidated balance sheets. See Note 8 to our consolidated financial statements included elsewhere in this report for additional information related to our debt instruments; for more information on our interest rate risk management and on our interest rate swap agreements, see Note 13 to our consolidated financial statements included elsewhere in this report.

Item 8. *Financial Statements and Supplementary Data.*

The information required in this Item 8 is included in this report as set forth in the "Index to Financial Statements" on page 109.

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, 2011, 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 evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their attestation 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 2011 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*

Directors and Executive Officers of our General Partner and its Delegate

Set forth below is information concerning the directors and executive officers of our general partner and KMR, the delegate of our general partner. All directors of our general partner are elected annually by, and may be removed by, Kinder Morgan (Delaware), Inc. as its sole common shareholder, and all directors of KMR are elected annually by, and may be removed by, our general partner as the sole holder of KMR's voting shares. Kinder Morgan (Delaware), Inc. is a wholly-owned subsidiary of Kinder Morgan Kansas, Inc. All officers of our general partner and all officers of KMR serve at the discretion of the board of directors of our general partner.

<u>Name</u>	<u>Age</u>	<u>Position with our General Partner and KMR</u>
Richard D. Kinder	67	Director, Chairman and Chief Executive Officer
C. Park Shaper.....	43	Director and President
Steven J. Kean.....	50	Executive Vice President and Chief Operating Officer
Ted A. Gardner.....	54	Director
Gary L. Hultquist.....	68	Director
Perry M. Waughtal	76	Director
Kimberly A. Dang	42	Vice President and Chief Financial Officer
Jeffrey R. Armstrong.....	43	Vice President (President, Terminals)
Thomas A. Bannigan.....	58	Vice President (President, Products Pipelines)
Richard T. Bradley	56	Vice President (President, CO ₂)
David D. Kinder	37	Vice President, Corporate Development and Treasurer
Joseph Listengart.....	43	Vice President, General Counsel and Secretary
Thomas A. Martin	50	Vice President (President, Natural Gas Pipelines)
James E. Street	55	Vice President, Human Resources and Administration

Richard D. Kinder is Director, Chairman and Chief Executive Officer of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Kinder has served as Director, Chairman and Chief Executive Officer of KMR since its formation in February 2001. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan Kansas, Inc. in October 1999. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. in February 1997. Mr. Kinder was elected President of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in July 2004 and served as President until May 2005. He also served as Chief Manager, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Chairman and Chief Executive Officer of KMI upon its conversion. Mr. Kinder is the uncle of David Kinder, Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Kinder's experience as Chief Executive Officer of KMR and of Kinder Morgan G.P., Inc., provide him with a familiarity with our strategy, operations and finances that can be matched by no one else. In addition, we believe that with Mr. Kinder's significant direct and indirect equity ownership in us, his economic interests are aligned with those of our other equity investors.

C. Park Shaper is Director and President of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Shaper was elected President of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in May 2005. He served as Executive Vice President of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. from July 2004 until May 2005. Mr. Shaper was elected Director of KMR and Kinder Morgan G.P., Inc. in January 2003 and of Kinder Morgan Kansas, Inc. in May of 2007. He was elected Vice President, Treasurer and Chief Financial Officer of KMR upon its formation in February 2001, and served as its Treasurer until January 2004, and its Chief Financial Officer until May 2005. He was elected Vice President, Treasurer and Chief Financial Officer of Kinder Morgan Kansas, Inc. in January 2000, and served as its Treasurer until January 2004, and its Chief Financial Officer until May 2005. Mr. Shaper was elected Vice President, Treasurer and Chief Financial Officer of Kinder Morgan G.P., Inc. in January 2000, and served as its Treasurer until January 2004 and its Chief Financial Officer until May 2005. He also served as President, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Director and President of KMI upon its conversion. He received a Masters of Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University. Mr. Shaper also has a Bachelor of Science degree in Industrial Engineering and a Bachelor of Arts degree in Quantitative Economics from Stanford University. Mr. Shaper is also a trust manager of Weingarten Realty Investors. Mr. Shaper's experience as President of KMR and Kinder Morgan G.P., Inc., together with his experience as an executive officer of various Kinder

Morgan entities, provide him valuable management and operational expertise and intimate knowledge of our business operations, finances and strategy.

Steven J. Kean is Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Kean was elected Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in January 2006. He also served as President, Natural Gas Pipelines of KMR and Kinder Morgan G.P., Inc. from July 2008 to November 2009. He served as Executive Vice President, Operations of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. from May 2005 to January 2006. He served as President, Texas Intrastate Pipeline Group from June 2002 until May 2005. He served as Vice President of Strategic Planning for the Kinder Morgan Gas Pipeline Group from January 2002 until June 2002. He also served as Chief Operating Officer, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Director, Executive Vice President and Chief Operating Officer of KMI upon its conversion. Mr. Kean received his Juris Doctor from the University of Iowa in May 1985 and received a Bachelor of Arts degree from Iowa State University in May 1982.

Ted A. Gardner is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Gardner was elected Director of KMR and Kinder Morgan G.P., Inc. in July 2011 to fill the vacancy left by Mr. C. Berdon Lawrence, who resigned from the KMR and Kinder Morgan G.P., Inc. boards of directors that same month. Since June 2005, Mr. Gardner has been a Managing Partner of Silverhawk Capital Partners in Charlotte, North Carolina. Formerly, he was a Director of Kinder Morgan, Inc. from 1999 to 2007, and was a Director of Encore Acquisition Company from 2001 to 2010. Mr. Gardner also served as Managing Partner of Wachovia Capital Partners and was a Senior Vice President of Wachovia Corporation from 1990 to June 2003. He is currently a Director of Summit Materials Holdings and Spartan Energy Partners. We believe Mr. Gardner's prior management, business and leadership experience, and his previous board experience with Kinder Morgan, Inc., provides us with the perspectives and judgment necessary to guide our business strategies, thereby qualifying him to serve as a director.

Gary L. Hultquist is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Hultquist was elected Director of KMR upon its formation in February 2001. He was elected Director of Kinder Morgan G.P., Inc. in October 1999. Since 1995, Mr. Hultquist has been the Managing Director of Hultquist Capital, LLC, a San Francisco-based strategic and merger advisory firm. Since 2009, Mr. Hultquist has also been Chairman of the board of directors of Prairie Bankers, LLC, a data center development company, and a Principal of NewCap Partners Inc., a FINRA-registered broker-dealer and investment bank, specializing in technology, mergers and acquisitions. Mr. Hultquist has over 20 years of experience as an investment banker and over 15 years experience practicing law. This combination of experience provides him an understanding of the business and legal risks applicable to us.

Perry M. Waughtal is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Waughtal was elected Director of KMR upon its formation in February 2001. Mr. Waughtal was elected Director of Kinder Morgan G.P., Inc. in April 2000. Since 1994, Mr. Waughtal has been the Chairman of Songy Partners Limited, an Atlanta, Georgia based real estate investment company. Mr. Waughtal was a Director of HealthTronics, Inc. from 2004 to 2009. We believe Mr. Waughtal's 30 years of experience with Hines Interests Limited Partnership, a privately owned, international real estate firm, including as Vice Chairman of development and operations and Chief Financial Officer, and 15 years of experience as Chairman of Songy Partners Limited provide him with planning, management, finance and accounting experience with, and an understanding of, large organizations with capital-intensive projects analogous to the types in which we typically engage, thereby qualifying him to serve as a director.

Kimberly A. Dang is Vice President and Chief Financial Officer of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mrs. Dang was elected Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in May 2005. She served as Treasurer of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. from January 2004 to May 2005. She was elected Vice President, Investor Relations of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in July 2002 and served in that role until January 2009. From November 2001 to July 2002, she served as Director, Investor Relations of KMR, Kinder Morgan G.P. Inc., and Kinder Morgan Kansas, Inc. She also served as Chief Financial Officer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President and Chief Financial Officer of KMI upon its conversion. Mrs. Dang received a Masters in Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University and a Bachelor of Business Administration degree in accounting from Texas A&M University.

Jeffrey R. Armstrong is Vice President (President, Terminals) of KMR and Kinder Morgan G.P., Inc. Mr. Armstrong became Vice President (President, Terminals) in July 2003. He served as President, Kinder Morgan Liquids Terminals LLC from March 1, 2001, when the company was formed via the acquisition of GATX Terminals, through July 2003. From 1994 to 2001, Mr. Armstrong worked for GATX Terminals, where he was General Manager of their East Coast

operations. He received his Bachelor's degree from the United States Merchant Marine Academy and an MBA from the University of Notre Dame.

Thomas A. Bannigan is Vice President (President, Products Pipelines) of KMR and Kinder Morgan G.P., Inc. and President and Chief Executive Officer of Plantation Pipe Line Company. Mr. Bannigan was elected Vice President (President, Products Pipelines) of KMR upon its formation in February 2001. He was elected Vice President (President, Products Pipelines) of Kinder Morgan G.P., Inc. in October 1999. Mr. Bannigan has served as President and Chief Executive Officer of Plantation Pipe Line Company since May 1998. Mr. Bannigan received his Juris Doctor, cum laude, from Loyola University in 1980 and received a Bachelors degree from the State University of New York in Buffalo.

Richard T. Bradley is Vice President (President, CO₂) of KMR and of Kinder Morgan G.P., Inc. and President of Kinder Morgan CO₂ Company, L.P. Mr. Bradley was elected Vice President (President, CO₂) of KMR upon its formation in February 2001 and Vice President (President, CO₂) of Kinder Morgan G.P., Inc. in April 2000. Mr. Bradley has been President of Kinder Morgan CO₂ Company, L.P. (formerly known as Shell CO₂ Company, Ltd.) since March 1998. Mr. Bradley received a Bachelor of Science in Petroleum Engineering from the University of Missouri at Rolla.

David D. Kinder is Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Kinder was elected Treasurer of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in May 2005. He was elected Vice President, Corporate Development of KMR, Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in October 2002. He served as manager of corporate development for Kinder Morgan Kansas, Inc. and Kinder Morgan G.P., Inc. from January 2000 to October 2002. He also served as Treasurer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President, Corporate Development and Treasurer of KMI upon its conversion. Mr. Kinder graduated cum laude with a Bachelors degree in Finance from Texas Christian University in 1996. Mr. Kinder is the nephew of Richard D. Kinder.

Joseph Listengart is Vice President, General Counsel and Secretary of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Listengart was elected Vice President, General Counsel and Secretary of KMR upon its formation in February 2001. He was elected Vice President and General Counsel of Kinder Morgan G.P., Inc. and Vice President, General Counsel and Secretary of Kinder Morgan Kansas, Inc. in October 1999. Mr. Listengart was elected Secretary of Kinder Morgan G.P., Inc. in November 1998 and has been an employee of Kinder Morgan G.P., Inc. since March 1998. He also served as General Counsel and Secretary of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President, General Counsel and Secretary of KMI upon its conversion. Mr. Listengart received his Masters in Business Administration from Boston University in January 1995, his Juris Doctor, magna cum laude, from Boston University in May 1994, and his Bachelor of Arts degree in Economics from Stanford University in June 1990.

Thomas A. Martin is Vice President (President, Natural Gas Pipelines) of KMR and Kinder Morgan G.P., Inc. Mr. Martin was elected Vice President (President, Natural Gas Pipelines) of KMR and Kinder Morgan G.P., Inc. in November 2009. Mr. Martin served as President, Texas Intrastate Pipeline Group from May 2005 until November 2009. From April 2003 to May 2005 he served as Vice President of Storage and Optimization for our Texas Intrastate Pipeline Group. Mr. Martin received a Bachelor of Business Administration degree from Texas A&M University.

James E. Street is Vice President, Human Resources and Administration of KMR, Kinder Morgan G.P., Inc., KMI and Kinder Morgan Kansas, Inc. Mr. Street was elected Vice President, Human Resources and Administration of KMR upon its formation in February 2001. He was elected Vice President, Human Resources and Administration of Kinder Morgan G.P., Inc. and Kinder Morgan Kansas, Inc. in August 1999. He has been Vice President, Human Resources and Administration of KMI since February 2011. Mr. Street received a Masters of Business Administration degree from the University of Nebraska at Omaha and a Bachelor of Science degree from the University of Nebraska at Kearney.

Corporate Governance

We have a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 comprised of Messrs. Gardner, Hultquist and Waughtal. Mr. Waughtal is the chairman of the audit committee and has been determined by the board to be an "audit committee financial expert." The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

We have not, nor has our general partner nor KMR, made, within the preceding three years, contributions to any tax-exempt organization in which any of our or KMR's independent directors serves as an executive officer that in any single fiscal year exceeded the greater of \$1.0 million or 2% of such tax-exempt organization's consolidated gross revenues.

We make available free of charge within the “Investors” information section of our internet Website, at www.kindermorgan.com, the governance guidelines, the charters of the audit committee, compensation committee and nominating and governance committee, and our code of business conduct and ethics (which applies to senior financial and accounting officers and the chief executive officer, among others). We intend to disclose any amendments to our code of business conduct and ethics that would otherwise be disclosed on Form 8-K and any waiver from a provision of that code granted to our executive officers or directors that would otherwise be disclosed on Form 8-K on our internet Website within four business days following such amendment or waiver. 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.

Interested parties may contact our lead director (Mr. Gardner, discussed in Item 13), the chairpersons of any of the board’s committees, the independent directors as a group or the full board by mail to Kinder Morgan Management, LLC, 500 Dallas Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the “Contact Us” section of our internet Website, at www.kindermorgan.com. Any communication should specify the intended recipient.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934 requires our directors and officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the Securities and Exchange Commission. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2011.

Item 11. *Executive Compensation.*

As is commonly the case for publicly traded limited partnerships, we have no officers. Under our limited partnership agreement, Kinder Morgan G.P., Inc., as our general partner, is to direct, control and manage all of our activities. Pursuant to a delegation of control agreement, Kinder Morgan G.P., Inc. has delegated to KMR the management and control of our business and affairs to the maximum extent permitted by our partnership agreement and Delaware law, subject to our general partner’s right to approve certain actions by KMR. The executive officers and directors of Kinder Morgan G.P., Inc. serve in the same capacities for KMR, and certain of those executive officers also serve as executive officers of KMI and of Kinder Morgan Kansas, Inc.

Except as indicated otherwise, all information in this report with respect to compensation of executive officers describes the total compensation received by those persons in all capacities for services rendered to us, our subsidiaries and our affiliates, including KMI and Kinder Morgan Kansas, Inc. In this Item 11, “we,” “our” or “us” refers to Kinder Morgan Energy Partners, L.P. and, where appropriate, Kinder Morgan G.P., Inc., KMR, KMI and Kinder Morgan Kansas, Inc.

Compensation Discussion and Analysis

Program Objectives

We seek to attract and retain executives who will help us achieve our primary business strategy objective of growing the value of our portfolio of businesses for the benefit of our unitholders. To help accomplish this goal, we have designed an executive compensation program that rewards individuals with competitive compensation that consists of a mix of cash, benefit plans and long-term compensation, with a majority of executive compensation tied to the “at risk” portions of the annual cash bonus.

The key objectives of our executive compensation program are to attract, motivate and retain executives who will advance our overall business strategies and objectives to create and return value to our unitholders. We believe that an effective executive compensation program should link total compensation to financial performance and to the attainment of short- and long-term strategic, operational, and financial objectives. We also believe it should provide competitive total compensation opportunities at a reasonable cost. In designing our executive compensation program, we have recognized that our executives have a much greater portion of their overall compensation at-risk than do our other employees. Consequently, we have tried to establish the at-risk portions of our executive total compensation at levels that recognize their much increased level of responsibility and their ability to influence business results.

Our executive compensation program is principally composed of the following two elements: (i) base cash salary; and (ii) possible annual cash bonus (reflected in the Summary Compensation Table below as Non-Equity Incentive Plan Compensation). We pay our executive officers a base salary not to exceed \$300,000, which we believe is below annual base salaries for comparable positions in the marketplace.

In addition, we believe that the compensation of our Chief Executive Officer, Chief Financial Officer and the executives named in the Summary Compensation Table below (collectively referred to in this Item 11 as our named executive officers), should be directly and materially tied to the financial performance of KMI and us, and should be aligned with the interests of our unitholders. Therefore, the majority of our named executive officers' compensation is allocated to the "at risk" portion of our compensation program—the annual cash bonus. Accordingly, for 2011, our executive compensation was weighted toward the cash bonus, payable on the basis of the achievement of (i) a dividend per share target by KMI; and (ii) a cash distribution per common unit target by us.

Our compensation is determined independently without the use of any compensation surveys. Nevertheless, we annually compare our executive compensation components with market information, consisting of third-party surveys in which we participate. The surveys we use in reviewing our executive compensation consist of the following: (i) Towers Executive Survey, in which approximately 300 to 400 companies participate; (ii) the Hewitt Executive Survey, in which approximately 400 companies participate; and (iii) the Natural Gas Transmission Industries Survey, in which companies in the natural gas industry participate. The purpose of this comparison is to ensure that our total compensation package operates effectively, remains both reasonable and competitive with the energy industry, and is generally comparable to the compensation offered by companies of similar size and scope as us. We also keep abreast of current trends, developments, and emerging issues in executive compensation, and if appropriate, will obtain advice and assistance from outside legal, compensation or other advisors.

We have endeavored to design our executive compensation program and practices with appropriate consideration of all tax, accounting, legal and regulatory requirements. Section 162(m) of the Internal Revenue Code limits the deductibility of certain compensation for executive officers to \$1,000,000 of compensation per year; however, if specified conditions are met, certain compensation may be excluded from consideration of the \$1,000,000 limit. Since the bonuses paid to our executive officers were paid under Kinder Morgan Inc.'s Annual Incentive Plan as a result of reaching designated financial targets established by Richard D. Kinder and KMR's compensation committee, we expect that all compensation paid to our executives would qualify for deductibility under federal income tax rules. Though we are advised that limited partnerships, such as us, are not subject to section 162(m), we have chosen to generally operate as if this code section does apply to us as a measure of appropriate governance.

Behaviors Designed to Reward

Our executive compensation program is designed to reward individuals for advancing our business strategies and the interests of our stakeholders, and prohibits engaging in any detrimental activities, such as performing services for a competitor, disclosing confidential information or violating appropriate business conduct standards. Each executive is held accountable to uphold and comply with company guidelines, which require the individual to maintain a discrimination-free workplace, to comply with orders of regulatory bodies, and to maintain high standards of operating safety and environmental protection.

Unlike many companies, we have no executive perquisites, supplemental executive retirement, non-qualified supplemental defined benefit/contribution, deferred compensation or split-dollar life insurance programs for our executive officers. We have no executive company cars or executive car allowances nor do we pay for financial planning services. Additionally, we do not own any corporate aircraft, and we do not pay for executives to fly first class. We believe that this area of our overall compensation package is below competitive levels for comparable companies; however, we have no current plans to change our policy of not offering such executive benefits or perquisite programs.

We do not have employment agreements (other than with Richard D. Kinder) or change of control agreements with our executive officers, although the KMI Class B shares held by our executive officers will fully vest upon a change of control of KMI. In connection with KMI's initial public offering in February 2011, one of our affiliated companies entered into severance agreements with eleven of our executive officers. See "—Other Compensation—Other Potential Post-Employment Benefits."

At his request, Richard D. Kinder receives \$1 of base salary per year from Kinder Morgan Kansas, Inc. Additionally, Mr. Kinder has requested that he receive no annual bonus or other compensation from us or any of our affiliates (other than the KMI Class B unit awards that he received in 2007 in connection with the going-private transaction). Mr. Kinder does not have any deferred compensation, supplemental retirement or any other special benefit, compensation or

perquisite arrangement with us, and each year, Mr. Kinder reimburses us for his portion of health care premiums and parking expenses.

Elements of Compensation

As outlined above, our executive compensation program is principally composed of the following two elements: (i) a base cash salary; and (ii) a possible annual cash bonus. With respect to our named executive officers other than our Chief Executive Officer, KMR's compensation committee reviews and approves annually the financial goals and objectives of both us and KMI that are relevant to the compensation of our named executive officers.

The KMR compensation committee solicits information from Richard D. Kinder and James E. Street (Vice President, Human Resources and Administration), with respect to the performance of C. Park Shaper, President, and Steven J. Kean, Executive Vice President and Chief Operating Officer. Similarly, the compensation committee solicits information from Messrs. Kinder, Shaper, Kean and Street with respect to the performance of the other named executive officers. The compensation committee also obtains information from Mr. Street with respect to compensation of comparable positions of responsibility at comparable companies. All of this information is taken into account by the compensation committee, which makes final determinations regarding compensation of the named executive officers. No named executive officer reviews his or her own performance or approves his or her own compensation.

Furthermore, if any of our general partner's or KMR's executive officers is also an executive officer of KMI, the compensation determination or recommendation (i) may be with respect to the aggregate compensation to be received by such officer from KMI, KMR, and our general partner that is to be allocated among them; or alternatively (ii) may be with respect to the compensation to be received by such executive officers from KMI, KMR or our general partner, as the case may be, in which case such compensation will be allocated among KMI, on the one hand, and KMR and our general partner, on the other hand.

In addition to the possible annual cash bonus discussed below (and reflected in the Summary Compensation Table as Non-Equity Incentive Plan Compensation), for the year ended December 31, 2011, the KMI compensation committee determined to award one-time cash bonuses to Messrs. Shaper and Listengart and Mrs. Dang in respect of their efforts in KMI's February 2011 initial public offering. See "—Summary Compensation Table" below.

Base Salary

Base salary is paid in cash. The base salary cap for our executive officers, with the exception of our Chairman and Chief Executive Officer who receives \$1 of base salary per year as described above, is an annual amount not to exceed \$300,000. Generally, we believe that our executive officers' base salaries are below base salaries for executives in similar positions and with similar responsibilities at companies of comparable size and scope, based upon independent salary surveys in which we participate.

Possible Annual Cash Bonus (Non-Equity Cash Incentive)

For the 2009 bonus year, our possible annual cash bonus was provided for under Kinder Morgan Kansas, Inc.'s Annual Incentive Plan, which became effective January 18, 2005. For the 2010 bonus year, Kinder Morgan Kansas, Inc.'s board of directors approved a new Annual Incentive Plan, which became effective January 1, 2010. For the 2011 bonus year, KMI's board of directors approved a new Annual Incentive Plan that mirrored the previous plan. The overall purpose of the Annual Incentive Plan is to increase our executive officers' and our employees' personal stake in the continued success of KMI, and us, by providing to them additional incentives through the possible payment of annual cash bonuses. Under the plan, a budget amount is established for annual cash bonuses at the beginning of each year that may be paid to our executive officers and other employees depending on whether KMI and its subsidiaries (including us) meet certain financial performance objectives (as discussed below). The amount included in our budget for bonuses is not allocated between our executive officers and non-executive officers. Assuming the financial performance objectives are met, the budgeted pool of bonus dollars is further assessed and potentially increased if the financial performance objectives are exceeded. The budget for bonuses also may be adjusted upward or downward based on KMI's and its subsidiaries' overall performance in other areas, including but not limited to safety and environmental goals and regulatory compliance.

All of KMI's employees and the employees of its subsidiaries, including KMGP Services Company, Inc., are eligible to participate in the plan, except employees who are included in a unit of employees covered by a collective bargaining agreement unless such agreement expressly provides for eligibility under the plan. However, only eligible employees who are selected by KMR's compensation committee will actually participate in the plan and receive bonuses.

The plan consists of two components: the executive plan component and the non-executive plan component. Our Chairman and Chief Executive Officer, and all employees who report directly to the Chairman, including all of the named executive officers, are eligible for the executive plan component; however, as stated elsewhere in this “Compensation Discussion and Analysis,” Richard D. Kinder has elected to not participate under the plan. As of December 31, 2011, excluding Mr. Kinder, eleven of our executive officers were eligible to participate in the executive plan component. All other U.S. and Canadian eligible employees were eligible for the non-executive plan component.

At or before the start of each calendar year (or later, to the extent allowed under Internal Revenue Code regulations), financial performance objectives based on one or more of the criteria set forth in the plan are established by KMR’s compensation committee. Two financial performance objectives were set for 2011 under both the executive plan component and the non-executive plan component. The two financial performance objectives were:

- \$4.60 in cash distributions per common unit by us (the same as our previously disclosed 2011 budget expectations); and
- \$1.16 in cash dividends per share paid during the year for KMI (including a \$0.29 per share dividend for the first quarter of 2011, which was prorated for the portion of the first quarter after KMI’s initial public offering).

A third objective which could potentially decrease or increase the budgeted pool of bonus dollars for 2011 was a goal to improve our environmental, health, and safety performance by (1) beating industry average incident rates; (2) improving incident rates compared to our previous three year averages.

At the end of 2011, the extent to which the financial performance objectives have been attained and the extent to which the bonus opportunity has been earned under the formula previously established by KMR’s compensation committee was determined. For 2011:

- we distributed \$4.61 in cash per common unit—generating enough cash from operations in 2011 to fully cover our cash distribution target; furthermore, we would have fallen just slightly short (approximately \$4 million) of meeting our budgeted excess cash coverage of \$37 million for 2011 had we not chosen to increase our distribution for the fourth quarter of 2011 by \$0.01, and if we would have received a Canadian tax refund that was expected in 2011, but will not be received until 2012; and
- KMI distributed \$1.18 in cash dividends per share.

Based on the above, the KMR compensation committee recommended that approximately 100% of the 2011 budgeted cash bonus opportunity be earned and funded under the plan (an increase from the 2010 funding level of 93%). The approved funding level includes any premium pay calculations for bonus awards paid to non-exempt employees.

In addition to determining the financial performance objectives under the Annual Incentive Plan, at or before the start of each calendar year, the compensation committee sets the bonus opportunities available to each executive officer. The table below sets forth the maximum bonus opportunities that could be payable by KMI and us collectively to the named executive officers for achievement of the threshold, target and maximum 2011 financial performance objectives established under the plan. If neither of the financial performance objectives was met, no bonus opportunity would be available to the named executive officers. The maximum payout to any individual under the plan for any year is \$3.0 million. The compensation committee may reduce the amount of the bonus actually paid to any executive officer from the amount of any bonus opportunity open to such executive officer. Because payments under the plan for our executive officers are determined by comparing actual performance to the performance objectives established each year for eligible executive officers chosen to participate for that year, it is not possible to accurately predict any amounts that will actually be paid under the executive portion of the plan over the life of the plan. The compensation committee set maximum bonus opportunities under the plan for 2011 for the executive officers at dollar amounts in excess of those which were expected to actually be paid under the plan. In fact, while achievement of the financial performance objectives sets the maximum bonus opportunity for each executive officer, the compensation committee has never awarded the maximum bonus opportunity to a current named executive officer. The actual payout amounts under the Non-Equity Incentive Plan Awards made for 2011 (paid in 2012) are set forth in the Summary Compensation Table in the column entitled “Non-Equity Incentive Plan Compensation.”

Kinder Morgan, Inc. Annual Incentive Plan Bonus Opportunities for 2011

<u>Name</u>	<u>Threshold (a)</u>	<u>Target (b)</u>	<u>Maximum (c)</u>
Richard D. Kinder (d)	\$ —	\$ —	\$ —
Kimberly A. Dang.....	500,000	1,000,000	1,500,000
Steven J. Kean.....	750,000	1,500,000	3,000,000
Joseph Listengart.....	500,000	1,000,000	1,500,000
C. Park Shaper.....	750,000	1,500,000	3,000,000

- (a) Represents the maximum bonus opportunity available to the executive officer if one of the financial performance objectives was met.
- (b) Represents the maximum bonus opportunity available to the executive officer if both of the financial performance objectives were met.
- (c) Represents the maximum bonus opportunity available to the executive officer if both of the financial performance objectives were exceeded by 10% or more.
- (d) Declined to participate.

The 2011 bonuses for our executive officers were overwhelmingly based on whether the established financial performance objectives were met. The compensation committee also considered, in a purely subjective manner, how well the executive officer performed his or her duties during the year. Information was solicited from relevant members of senior management regarding the performance of our named executive officers (described following), and determinations and recommendations were made at the regularly scheduled first quarter board and compensation committee meetings held in January 2012. Other factors considered by the compensation committee primarily consisted of the amount of the bonus paid to the executive officer in the prior year and market data about compensation of comparable positions of responsibility at comparable companies, consisting of the compensation surveys referred to above. With respect to using these other factors in assessing performance, KMR's compensation committee did not find it practicable to, and did not, use a "score card" or quantify or assign relative weight to the specific criteria considered. The amount of a downward adjustment, subject to the maximum bonus opportunity that was established at the beginning of the year, was not subject to a formula. Specific aspects of an individual's performance were not identified in advance. Rather, adjustments were based on KMR's compensation committee's judgment, giving consideration to the totality of the record presented, including the individual's performance and the magnitude of any other positive or negative factors.

Upon the occurrence of a change in control the compensation committee may take any action with respect to outstanding awards that it deems appropriate; and in the event that such action is to distribute an award, the award will be distributed in a lump sum no later than 30 days after the change in control. Under the plan, "change in control" means (1) that any person, other than a permitted holder (as defined below), becomes the beneficial owner of securities representing 50% or more of the voting power of KMI; (2) a sale, merger or other business combination as a result of which transaction the voting securities of KMI, outstanding immediately before such transaction do not continue to represent at least 50% of the voting power of KMI after giving effect to such transaction; (3) the sale or transfer of all or substantially all of the assets of KMI or one of its parent entities, including us, other than to an entity of which more than 50% of the voting power is held by permitted holders (as defined below); (4) during any period of two consecutive years following the closing of KMI's initial public offering, individuals who were directors at the beginning of the period or whose election or nomination for election by KMI's stockholders was approved by a vote of two-thirds of the directors then still in office who had been directors at the beginning of the period or previously so approved, cease for any reason other than normal retirement, death or disability to constitute at least a majority of the board of directors then in office; or (5) the stockholders of KMI approve a plan of complete liquidation of KMI or an agreement for the sale or disposition by KMI of all or substantially all of its assets. Under the plan, a "permitted holder" means Richard D. Kinder and investment funds advised by or affiliated with Goldman, Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC.

If, in connection with a change in control, Richard D. Kinder is no longer our Chairman:

- each participant under the executive component of the plan will be deemed to have earned 100% of the bonus opportunity available to him or her, unless the compensation committee has previously determined that the participant should receive a lesser percentage of the bonus opportunity;

- each participant under the non-executive component of the plan will receive an award equal to the award most recently paid to such participant under the Annual Incentive Plan, or if no awards have been paid under the plan, an award equal to the most recent award paid to such participant under any prior Annual Incentive Plan; and
- the awards to executive and non-executive participants will be paid in a cash lump sum within 30 days after the change in control.

Compensation Related to the Going-Private Transaction

In connection with Kinder Morgan Kansas, Inc.'s going-private transaction, members of our management were awarded Kinder Morgan Holdco LLC Class A-1 and Class B units. In accordance with generally accepted accounting principles, we are required to recognize compensation expense in connection with the Class A-1 and Class B units over the expected life of such units; however, we do not have any obligation, nor did we pay any amounts related to these compensation expenses (all expenses were borne by the Sponsor Investors and Mr. Kinder), and since we were not responsible for paying these expenses, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet. The awards and terms of the Class B units granted to members of our management were determined after extensive negotiations between management and the Sponsor Investors with respect to which management agreed to forego any long-term executive compensation at least until the Sponsor Investors sell their interests in KMI.

Comparison of Class B Units to Class B Shares. The Class B units were converted into Class B shares in connection with KMI's initial public offering. The Class B shares are intended to substantially preserve the economic rights of the Class B units in Kinder Morgan Holdco LLC but differ from the Class B units in certain respects, including the following:

- Class B units were subject to time vesting, with one-third vesting on the third, fourth and fifth anniversaries of the date of their issuance. All distributions with respect to the non-vested portion of such Class B units are held in escrow pending the vesting or forfeiture of such Class B units. Class B shares are not subject to time vesting. As a result, holders of Class B shares are entitled to receive and retain any distributions on, and shares of KMI Class P common stock issued upon conversion of, such Class B shares;
- the amount of Class B units forfeited upon termination of a holder's employment would depend on the reason for such termination and other factors such as time vesting and the level of cumulative distributions made by KMI as of a relevant date. Prior to a change of control, all non-time-vested Class B units would be forfeited upon termination of a holder's employment for any reason. With respect to time-vested Class B units, all such Class B units would be forfeited upon termination of a holder's employment for cause, no Class B units would be forfeited upon termination of a holder's employment for death or disability and all or a portion of Class B units would be forfeited upon termination of a holder's employment for other reasons based on the level of cumulative distributions made by KMI as of the date of termination. The amount of Class B shares forfeited will be based solely on the reason for the termination of employment. No Class B shares will be forfeited upon termination of a holder's employment for death or disability. Half of a holder's Class B shares will be forfeited upon termination of a holder's employment by such holder for good reason or termination of a holder's employment by us without cause. All Class B shares will be forfeited upon termination of a holder's employment for any other reason, including termination for cause;
- amounts in respect of forfeited Class B units would be transferred to an incentive pool and could be paid to other members of management (excluding Mr. Kinder) in the discretion of the chief manager and subject to certain unitholder approvals. Forfeited Class B shares will automatically become treasury shares, and KMI will transfer the forfeited Class B shares into a trust. Any property in the trust, including dividends, proceeds or earnings received with respect to such Class B shares, may be distributed to new or existing members of management (excluding Mr. Kinder) in any proportion at the election of KMI's chief executive officer and subject to the consent of a majority of KMI's directors nominated by Sponsor Investors;
- holders of forfeited Class B units that were time-vested would have received certain levels of distributions even after such holder's termination of employment depending on the level of cumulative distributions made by KMI as of the date of termination. Under specified circumstances, a holder of Class B shares who otherwise would forfeit such Class B shares upon such holder's termination of employment will retain his or her Class B shares until such holder has received a specified amount of total value, even if distributed after such holder's termination;

- if a holder of Class B units was terminated for any reason, KMI could repurchase his or her Class B units generally at fair market value. KMI does not have a right of repurchase with respect to the Class B shares; and
- Class B units would fully vest upon a change of control. Class B shares are not subject to forfeiture after a change of control.

Under our shareholders agreement, “change of control” means (1) the acquisition by any person or group, other than permitted holders (as defined below), by way of merger, amalgamation, consolidation or other business combination or purchase of beneficial ownership of more than 50% of our total voting power after giving effect to such transaction; (2) a sale, merger or similar transaction or related series of transactions involving us, as a result of which persons who collectively held 100% of our total voting power immediately prior to such transaction do not collectively hold more than 50% of our total voting power after giving effect to such transaction unless (a) the persons who collectively held 100% of our total voting power continue to hold at least 35% of our total voting power; (b) no other person or group holds more than 35% of our total voting power; and (c) either Richard D. Kinder or Park Shaper is a senior executive officer; or (3) the sale or transfer of all or substantially all of our assets, and our subsidiaries’, taken as a whole, other than to an entity of which more than 50% of the voting power is held by a permitted holder or by persons who held more than 50% of our total voting power immediately prior to such transaction. Under the shareholders agreement, “permitted holders” means the Sponsor Investors and their successors and permitted transferees.

Comparison of Class A-1 Units to Class C Shares. The Class A-1 units converted into the Class C shares in connection with KMI’s initial public offering. The Class C shares are intended to substantially preserve the economic rights of the Class A-1 units in Kinder Morgan Holdco LLC but differ from the Class A-1 units in certain respects, including the following:

- Class A-1 units were subject to forfeiture if a holder was terminated for cause. Class C shares are not subject to forfeiture; and
- if the employment of a holder of Class A-1 units was terminated for any reason, KMI could have repurchased his or her Class A-1 units generally at fair market value. KMI does not have a right of repurchase with respect to the Class C shares.

Class B Share Plan and Class B Share Trust. The Class B shares may be forfeited by our management under the circumstances described above. All forfeited Class B shares will automatically become treasury shares, and KMI will transfer the forfeited Class B shares to a trust established solely to hold these Class B shares, together with any dividends, proceeds received in respect of these Class B shares, shares of KMI Class P common stock issued in connection with the conversion of these Class B shares or earnings with respect to such property. KMI has established the Class B share plan, which is a long-term compensation plan, to govern the terms of awards in respect of forfeited Class B shares and related property in the Class B share trust. Pursuant to the Class B share plan and KMI’s shareholders agreement, each item of property in the trust may be distributed separately from the underlying Class B shares to members of new or existing management (other than Richard D. Kinder), as designated by KMI’s chief executive officer and approved by a majority of the members of KMI’s board of directors nominated by the Sponsor Investors. All property held in the trust on May 31, 2015 will be distributed proportionally to the holders of Class B shares as of May 31, 2015. KMI has agreed to pay the costs of the Class B share trust, including the fees of the independent trustee, but does not expect these costs to be material.

Other Compensation

Kinder Morgan, Inc. Savings Plan. The Kinder Morgan, Inc. Savings Plan is a defined contribution 401(k) plan. The savings plan permits all full-time employees of Kinder Morgan Kansas, Inc. and those of KMGP Services Company, Inc., including the named executive officers, to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. For more information on this plan, see Note 9 “Employee Benefits—Kinder Morgan Savings Plan” to our consolidated financial statements included elsewhere in this report. As a result of a cost savings effort in 2009, all officers with the position of vice president or higher, including our named executive officers, were suspended from receiving any company contributions commencing February 15, 2009. Company contributions for these employees were reinstated effective February 1, 2010.

Kinder Morgan, Inc. Cash Balance Retirement Plan. Employees of Kinder Morgan Kansas, Inc. and KMGP Services Company, Inc., including the named executive officers, are also eligible to participate in the Kinder Morgan, Inc. Retirement Plan, referred to as the Cash Balance Retirement Plan, a cash balance plan. Employees accrue benefits

through a Personal Retirement Account, referred to as the PRA, in the Cash Balance Retirement Plan. KMI allocates contribution credits equivalent to 3% of eligible compensation every pay period to participants' PRAs. For plan years prior to 2011, interest was credited to the PRA at the 30-year U.S. Treasury bond rate published in the Internal Revenue Bulletin for the November of the prior year. Beginning January 1, 2011, interest is credited to the PRA at the 5-year U.S. Treasury bond rate published in the Internal Revenue Bulletin for the November of the prior year, plus 0.25%. Employees become 100% vested in the plan after three years and may take a lump sum distribution upon termination of employment or retirement. As a result of a cost savings effort in 2009, all company contributions to the plan were suspended from April 12, 2009 through December 31, 2009. Company contributions were reinstated effective January 1, 2010.

The following table sets forth the estimated actuarial present value of each named executive officer's accumulated pension benefit as of December 31, 2011, under the provisions of the Cash Balance Retirement Plan. With respect to our named executive officers, the benefits were computed using the same assumptions used for financial statement purposes, assuming current remuneration levels without any salary projection, and assuming participation until normal retirement at age 65. These benefits are subject to federal and state income taxes, where applicable, but are not subject to deduction for social security or other offset amounts.

Pension Benefits				
Name	Plan Name	Current Credited Yrs of Service	Present Value of Accumulated Benefit (a)	Contributions During 2011
Richard D. Kinder	Cash Balance	11	\$ -	\$ -
Kimberly A. Dang	Cash Balance	10	61,760	8,280
Steven J. Kean	Cash Balance	10	73,689	8,469
Joseph Listengart	Cash Balance	11	84,514	8,641
C. Park Shaper	Cash Balance	11	84,514	8,641

(a) The present values in the Pension Benefits table are current year-end balances.

Contingent Payment Obligations Under Shareholders Agreement. KMI has certain contingent payment obligations under the terms of its shareholders agreement that may be considered compensation to holders of Class B shares and Class C shares, including the agreement to pay certain tax compliance expenses for a holder of Class B shares or Class C shares in certain events related to such holder's ownership of Class B shares or Class C shares.

Potential Payments Upon Termination or Change-in-Control. Our named executive officers (excluding Richard D. Kinder) are entitled to certain benefits in the event their employment is terminated by KMI without cause or by them with good reason, whether or not related to a change in control. See "—Other Potential Post-Employment Benefits—Severance Agreements" below for a description of the terms. Mr. Kinder is also entitled to certain benefits under his employment agreement upon his termination by Kinder Morgan Kansas, Inc. without cause or by him with good reason, whether or not related to a change in control. See "Other Potential Post-Employment Benefits—Employment Agreement" below for a description of the terms. Upon termination of employment of a named executive officer due to death or disability (as determined in accordance with our long-term disability plan covering such employee), all of his or her KMI Class B shares will no longer be subject to forfeiture. In the event of a termination of employment of a named executive officer by KMI without "cause" or by a named executive officer with "good reason" (as each such term is defined in KMI's shareholders agreement and described under "Other Potential Post-Employment Benefits—Severance Agreements"), 50% of his or her KMI Class B shares will no longer be subject to forfeiture. In addition, all unvested KMI Class B shares will no longer be subject to forfeiture upon a change of control (as defined in KMI's shareholders agreement and described under "—Compensation Related to the Going-Private Transaction—Comparison of Class B Units to Class B Shares").

The following tables list separately the potential payments and benefits upon a change in control of KMI and the potential payments and benefits upon a termination of employment for our named executive officers. The tables assume the triggering event for the payments or provision of benefits occurred on December 31, 2011. Actual amounts payable to each executive listed below upon termination can only be determined definitively at the time of each executive's actual departure. In addition to the amounts shown in the tables below, each executive would receive payments for amounts of base salary and vacation time accrued through the date of termination and payment for any reimbursable business expenses incurred prior to the date of termination.

Potential Payments Upon Termination of Employment or Change in Control for Richard D. Kinder

	Termination Payment	Benefit Continuation	Value of KMI Class B Shares No Longer Subject to Forfeiture(d)
Termination without “cause” or “good reason” or due to “change in duties”(a)(c) ..	\$ 2,250,000	\$ 34,320	\$ N/A
Termination due to death or “disability”(a)(b).....	750,000	-	N/A
Upon a change in control.....	N/A	N/A	N/A

- (a) As such terms are defined in Mr. Kinder’s employment agreement and described under “—Other Potential Post-Employment Benefits—Employment Agreement.”
- (b) If Mr. Kinder becomes disabled, he is eligible for the same medical benefits as most other employees.
- (c) With respect to Class B shares, as the terms “cause” and “good reason” are defined in KMI’s shareholders agreement and described under “—Other Potential Post-Employment Benefits—Severance Agreements.”
- (d) Because the number of Class P shares into which the Class B shares of a series will convert depends on the total value received in excess of an agreed upon return threshold by the holders of the corresponding series of Class A shares when such Class A shares are converted into Class P shares, the market value of the Class B shares is not readily determinable.

Potential Payments Upon Termination of Employment or Change in Control for Other Named Executive Officers

Name	Termination Without Cause or Good Reason		Value of KMI Class B Shares No Longer Subject to Forfeiture(a)	
	Salary Continuation	Benefit Continuation	Upon Change in Control or Termination due to Death or Disability	Upon Termination Without Cause or for Good Reason
Kimberly A. Dang	\$ 300,000	\$ 17,160	\$ N/A	\$ N/A
Steven J. Kean	300,000	17,160	N/A	N/A
Joseph Listengart.....	300,000	17,160	N/A	N/A
C. Park Shaper.....	600,000	34,320	N/A	N/A

- (a) Because the number of Class P shares into which the Class B shares of a series will convert depends on the total value received in excess of an agreed upon return threshold by the holders of the corresponding series of Class A shares when such Class A shares are converted into Class P shares, the market value of the Class B shares is not readily determinable.

Other Potential Post-Employment Benefits

Employment Agreement. On October 7, 1999, Richard D. Kinder entered into an employment agreement with Kinder Morgan Kansas, Inc. pursuant to which he agreed to serve as its Chairman and Chief Executive Officer. His employment agreement provides for a term of three years and one year extensions on each anniversary of October 7th. Mr. Kinder, at his initiative, accepted an annual salary of \$1 to demonstrate his belief in our long-term viability. Mr. Kinder continues to accept an annual salary of \$1, and he receives no other compensation from us.

We believe that Mr. Kinder’s employment agreement contains provisions that are beneficial to us and accordingly, Mr. Kinder’s employment agreement is extended annually at the request of KMI’s and KMR’s boards of directors. For example, with limited exceptions, Mr. Kinder is prevented from competing in any manner with Kinder Morgan Kansas, Inc. or any of its subsidiaries, while he is employed by Kinder Morgan Kansas, Inc. and for 12 months following the termination of his employment with Kinder Morgan Kansas, Inc. The employment agreement provides that he will receive a severance payment equal to \$2.25 million in the event his employment is terminated without “cause” or in the event he is subject to a “change in duties” without his consent. His employment agreement also provides that in the event of his death or termination due to his total and permanent disability, he or his estate will receive an amount equal to the greater of his annual salary (\$1) or \$750,000, and in the case of his total and permanent disability, such amount will be an annual amount until the effective date of termination of employment. In addition, under the terms of KMI’s shareholders

agreement, Mr. Kinder also has agreed not to compete with KMI or any of its subsidiaries for an additional period of one year and not to solicit KMI's or any of its subsidiaries' employees or interfere with certain of its business relationships during the term of his employment and for two years thereafter.

Upon a change in control and a termination of Mr. Kinder's employment by Kinder Morgan Kansas, Inc. or by Mr. Kinder, certain payments made to him could be subject to the excise tax imposed on "excess parachute payments" by the Internal Revenue Code. Pursuant to his employment agreement, Mr. Kinder is entitled to have his compensation "grossed up" for all such excise taxes and any federal, state and local taxes applicable to such gross-up payment (including any penalties and interest). We estimate the amount of such gross up payment for Mr. Kinder's termination payment and benefits to be approximately \$1.05 million. The estimate of "excess parachute payments" for purposes of these calculations does not take into account any mitigation for payments which could be shown (under the facts and circumstances) not to be contingent on a change in control or for any payments being made in consideration of non-competition agreements or as reasonable compensation. The gross-up calculations assume an excise tax rate of 20%, a statutory federal income tax rate of 35%, and a Medicare tax rate of 1.45%. If upon a change in control Mr. Kinder's employment does not terminate, he would only be entitled to the immediate vesting of any KMI Class B shares.

Under the employment agreement, "cause" means (1) a grand jury indictment or prosecutorial information charging Mr. Kinder with illegal or fraudulent acts, criminal conduct or willful misconduct; (2) a grand jury indictment or prosecutorial information charging Mr. Kinder with any criminal acts involving moral turpitude; (3) grossly negligent failure by Mr. Kinder to perform his duties in a manner which he has reason to know is in Kinder Morgan Kansas, Inc.'s best interest; (4) bad faith refusal by Mr. Kinder to carry out reasonable instructions of the board of directors of Kinder Morgan Kansas, Inc.; and (5) a material violation by Mr. Kinder of any of the terms of the employment agreement.

Under the employment agreement, "change in duties" means, without Mr. Kinder's written consent, any of the following (1) a significant reduction in the nature, scope of authority or duties of Mr. Kinder; (2) a substantial reduction in Mr. Kinder's existing annual base salary or bonus opportunity; (3) receipt of employee benefits by Mr. Kinder that are materially inconsistent with the employee benefits provided by KMI to executives with comparable duties; or (4) a change of more than 50 miles in the location of Mr. Kinder's principal place of employment.

Severance Agreements. In connection with KMI's initial public offering, a subsidiary of KMI entered into severance agreements with respect to eleven of our executive officers (including our named executive officers other than Richard D. Kinder) that provide for severance in the amount of the executive's salary plus benefits during the executive's non-compete period, ranging from one to two years following the executive's termination of employment, if the executive voluntarily terminates his or her employment for "good reason" or the executive's employment with KMI and its subsidiaries is terminated "without cause." The other employees who did not enter into severance agreements with KMI are eligible for the same severance policy as all regular full time U.S.-based employees not covered by a bargaining agreement, which caps severance payments at an amount equal to six months of salary.

Under the severance agreements, "cause" means any of the following (1) conviction of a felony; (2) commission of fraud or embezzlement against us or any of our subsidiaries; (3) gross neglect of, or gross or willful misconduct in connection with the performance of, duties that is not cured within 30 days after written notice; (4) willful failure or refusal to carry out reasonable and lawful instructions of the Chief Executive Officer or the board of directors that is not cured within 30 days after written notice; (5) failure to perform duties and responsibilities as the individual's primary business activity; (6) judicial determination that the individual breached fiduciary duties; (7) willful and material breach of the shareholders agreement, certificate of incorporation or bylaws that is not cured within 30 days after written notice; or (8) material breach of a non-compete provision in the case of specified officers that is not cured with 30 days after written notice.

Under the shareholders agreement, "good reason" occurs when one of the following events occurs without an employee's consent, such employee provides written notice, such event is not corrected after such notice and the employee resigns (1) material diminution in the employee's duties and responsibilities; (2) material reduction in the employee's annual base salary or aggregate benefits; (3) material reduction in the employee's bonus opportunity; (4) relocation of the employee's primary place of employment by more than 50 miles; or (5) willful and intentional breach of the shareholders agreement by us that has a material and adverse effect on the employee.

Summary Compensation Table

The following table shows compensation paid or otherwise awarded to (i) our principal executive officer; (ii) our principal financial officer; and (iii) our three most highly compensated executive officers (other than our principal executive officer and principal financial officer) serving at fiscal year end 2011 (collectively referred to as the "named

executive officers”) for services rendered to us, our subsidiaries or our affiliates, including KMI and Kinder Morgan Kansas, Inc. (collectively referred to as the KMI affiliated entities), during fiscal years 2011, 2010 and 2009. The amounts in the columns below represent the total compensation paid or awarded to the named executive officers by all the KMI affiliated entities, and as a result, the amounts are in excess of the compensation expense allocated to, recognized and paid by us for services rendered to us.

Name and Principal Position	Year	(a)		(b)	(c)	(d)	Total
		Salary	Bonus	Non-Equity Incentive Plan Compensation	Change in Pension Value	All Other Compensation	
Richard D. Kinder.....	2011	\$ 1	\$ -	-	-	-	1
Director, Chairman and	2010	1	-	-	-	-	1
Chief Executive Officer	2009	1	-	-	-	-	1
Kimberly A. Dang.....	2011	300,000	175,000	625,000	8,280	13,330	1,121,610
Vice President and	2010	294,444	-	500,000	9,544	11,704	815,692
Chief Financial Officer	2009	257,692	-	550,000	4,243	3,115	815,050
Steven J. Kean.....	2011	300,000	-	1,250,000	8,469	15,028	1,573,497
Executive Vice President	2010	294,444	-	1,000,000	10,058	13,247	1,317,749
And Chief Operating Officer	2009	257,692	-	1,250,000	4,683	4,251	1,516,626
Joseph Listengart	2011	300,000	250,000	750,000	8,641	13,330	1,321,971
Vice President, General	2010	294,444	-	749,000	10,524	11,665	1,065,633
Counsel and Secretary	2009	257,692	-	925,000	5,082	2,866	1,190,640
C. Park Shaper	2011	300,000	250,000	1,300,000	8,641	14,170	1,872,811
Director and President	2010	294,444	-	1,040,000	10,524	12,925	1,357,893
	2009	257,692	-	1,300,000	5,082	3,971	1,566,745

(a) Represents bonus payments awarded and paid by KMI to the executive officers in connection with their efforts in KMI’s February 2011 initial public offering.

(b) Represents amounts paid according to the provisions of the Annual Incentive Plan then in effect. Amounts were earned in the fiscal year indicated but were paid in the next fiscal year.

(c) Represents the 2011, 2010 and 2009, as applicable, change in the actuarial present value of accumulated defined pension benefit (including unvested benefits) according to the provisions of KMI’s Cash Balance Retirement Plan.

(d) Amounts include value of contributions to the KMI Savings Plan (a 401(k) plan), value of group-term life insurance exceeding \$50,000, and taxable parking subsidy. Amounts in 2011, 2010 and 2009 representing the value of contributions to the KMI Savings Plan are \$12,250, \$11,022 and \$2,308, respectively.

Grants of Plan-Based Awards

The following supplemental compensation table shows compensation details on the value of all non-guaranteed and non-discretionary incentive awards granted during 2011 to our named executive officers. The table includes awards made during or for 2011. The information in the table under the caption “Estimated Future Payouts Under Non-Equity Incentive Plan Awards” represents the threshold, target and maximum amounts payable under the Kinder Morgan, Inc. Annual Incentive Plan for performance in 2011. Amounts actually paid under that plan for 2011 are set forth in the Summary Compensation Table under the caption “Non-Equity Incentive Plan Compensation.”

Name	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(a)		
	Threshold	Target	Maximum
Richard D. Kinder.....	\$ -	\$ -	\$ -
Kimberly A. Dang.....	500,000	1,000,000	1,500,000
Steven J. Kean.....	750,000	1,500,000	3,000,000
Joseph Listengart	500,000	1,000,000	1,500,000
C. Park Shaper	750,000	1,500,000	3,000,000

- (a) See “—Compensation Discussion and Analysis—Elements of Compensation” and “—Possible Annual Cash Bonus (Non-Equity Cash Incentive)” above for further discussion of these awards.

Outstanding Equity Awards at Fiscal Year-End

Option Awards and Stock Awards

None of the named executive officers has been awarded any stock options, restricted stock or similar stock-based awards, and we do not expect to grant any such awards to the named executive officers while the Sponsor Investors hold Class A shares.

Awards of Participation Interests in Going-Private Transaction

The holders of KMI’s Class P common stock do not bear any of the economic cost of, and are not diluted by, the KMI Class B shares, and the KMI Class B shares and the conversions of KMI Class B shares into KMI Class P shares do not impact the per share dividends paid on the KMI Class P shares or the aggregate dividends KMI pays to its shareholders. In connection with Kinder Morgan Kansas, Inc.’s going-private transaction, members of management, including the named executive officers, were awarded KMI Class B units as participation interests. The awards and terms of the KMI Class B units, determined after extensive negotiations between KMI management and the Sponsor Investors, provided that the investors in the going-private transaction would bear the economic burden of any value of the KMI Class B units, in exchange for which management agreed to forego any long-term compensation at least until the Sponsor Investors sell their interests in KMI. The KMI Class B units were converted into KMI Class B shares in connection with KMI’s initial public offering, and the terms of the KMI Class B shares continued to provide that the investors in the going-private transaction, and thus not the public shareholders, would bear the economic cost related to any KMI Class B share value. The aggregate amount of KMI’s Class P common stock into which the KMI Class A shares, KMI Class B shares and KMI Class C shares can convert is fixed. The conversion of KMI Class B shares into KMI Class P shares reduces the number of KMI Class P shares into which the KMI Class A shares and KMI Class C shares can convert. Therefore, KMI views the KMI Class B shares, along with the KMI Class A shares and KMI Class C shares, as participation interests in the going-private transaction, rather than as awards of stock-based compensation.

The KMI Class B shares are not subject to time vesting but may be forfeited upon termination of employment. In addition, the number of KMI Class P shares into which the KMI Class B shares of a series will convert depends on the total value in excess of an agreed upon return threshold received by the holders of the corresponding series of KMI Class A shares when such KMI Class A shares are converted into KMI Class P shares. As a result, the remaining KMI Class B shares of a series may convert into zero KMI Class P shares if the return threshold is not met.

The following table sets forth the number of KMI Class B shares held by each named executive officer as of December 31, 2011. As noted above, the holders of KMI Class P common stock do not bear any of the economic cost of, and are not diluted by, the KMI Class B shares, and the KMI Class B shares and the conversions of KMI Class B shares into KMI Class P shares do not impact the per share dividends paid on the KMI Class P shares or the aggregate dividends KMI pays to its shareholders.

Name	Number of shares	Market value of shares(d)
Richard D. Kinder(a).....	37,653,039	N/A
Kimberly A. Dang(b)	2,353,315	N/A
Steven J. Kean	7,530,608	N/A
Joseph Listengart.....	3,765,304	N/A
C. Park Shaper(c)	10,354,586	N/A

- (a) Includes 12,551,013 Class B shares that Mr. Kinder transferred to a limited partnership. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in those shares.
- (b) All of such Class B shares have been transferred by Mrs. Dang to a limited partnership. Mrs. Dang disclaims 10% of any beneficial and pecuniary interest in those shares.
- (c) All of such Class B shares have been transferred by Mr. Shaper to a limited partnership. Mr. Shaper disclaims 21% of any beneficial and pecuniary interest in those shares.

- (d) Because the number of Class P shares into which the Class B shares of a series will convert depends on the total value received in excess of an agreed upon return threshold by the holders of the corresponding series of Class A shares when such Class A shares are converted into Class P shares, the market value of the Class B shares is not readily determinable. Assuming all of the outstanding Class A shares were converted into Class P shares as of December 30, 2011 (the last trading day of the year) and such Class P shares were sold to third parties for net proceeds of \$32.17 per share (the closing market price of the Class P shares on December 30, 2011), the Class B shares held by the named executive officers would convert into the following numbers of Class P shares: Mr. Kinder – 29,248,080; Mrs. Dang – 1,828,005; Mr. Kean – 5,849,616; Mr. Listengart – 2,924,808; and Mr. Shaper – 8,043,222. These Class P shares would have the following indicated market values as of December 30, 2011: Mr. Kinder – \$940,910,739; Mrs. Dang – \$58,806,921; Mr. Kean – \$188,182,148; Mr. Listengart – \$94,091,074; and Mr. Shaper – \$258,750,453. All Class P shares and associated value received by the Class B shareholders, including the named executive officers, will reduce the number of Class P shares and value that otherwise would have been received by Richard D. Kinder and the Sponsor Investors, as the only remaining holders of Class A shares, and will not impact the public shareholders. As such, the net value realized by Mr. Kinder will be significantly less than as indicated above.

Stock Vested

As described above under “Outstanding Equity Awards at Fiscal Year-End,” the Class B shares are not subject to time vesting. However, viewing the conversion of Class B shares into Class P shares as “vesting” of stock awards, the following table sets forth the number of Class P shares acquired by the named executive officers upon the conversions of Class B shares and the value realized upon such conversions and from dividends during 2011. The Class P shares acquired and value realized set forth in the following table reduced both the number of Class P shares and the amount of dividends that otherwise would have been received by the Investors with respect to their Class A shares. These shares acquired and value realized in no way diluted, or impacted the dividends received by, KMI’s public shareholders.

Name	Number of Class P shares acquired(a)	Value realized(b)
Richard D. Kinder(c).....	1,654,302	\$ 60,939,967
Kimberly A. Dang(d).....	103,394	3,808,751
Steven J. Kean	330,860	12,187,982
Joseph Listengart.....	165,430	6,093,991
C. Park Shaper(e)	454,933	16,758,489

- (a) The number of Class B shares converted were as follows: Mr. Kinder – 2,346,962; Mrs. Dang – 146,685; Mr. Kean – 469,392; Mr. Listengart – 234,696; and Mr. Shaper – 645,414.
- (b) Calculated as the number of Class P shares acquired multiplied by \$27.77, the closing market price of the Class P shares on November 16, 2011, the date of conversion. Also includes the amount of “priority dividends” (as defined in KMI’s certificate of incorporation) received on the Class B shares, which dividends reduce the value that will ultimately be realized on the Class B shares. The amounts of the priority dividends received in 2011 were as follows: Mr. Kinder – \$15,000,000; Mrs. Dang – \$937,500; Mr. Kean – \$3,000,000; Mr. Listengart – \$1,500,000; and Mr. Shaper – \$4,125,000.
- (c) Mr. Kinder transferred 33% of his Class B shares to a limited partnership. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.
- (d) Mrs. Dang transferred all of her Class B shares to a limited partnership. Mrs. Dang disclaims 10% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.
- (e) Mr. Shaper transferred all of his Class B shares to a limited partnership. Mr. Shaper disclaims 21% of any beneficial and pecuniary interest in the shares held and value realized by the limited partnership.

Risks Associated with Compensation Practices

KMGP Services Company, Inc., Kinder Morgan Kansas, Inc., and Kinder Morgan Canada Inc. employ all persons necessary for the operation of our business, and in our opinion, our compensation policies and practices for all persons necessary for the operation of our business do not create risks that are reasonably likely to have a material adverse effect on our business, financial position, results of operations or cash flows. Our belief is based on the fact that our employee compensation—primarily consisting of annual salaries and cash bonuses—is based on performance that does not reward risky behavior and is not tied to entering into transactions that pose undue risks to us.

Director Compensation

Compensation Committee Interlocks and Insider Participation.

The compensation committee of KMR functions as our compensation committee. KMR's compensation committee is comprised of Mr. Ted A. Gardner, Mr. Gary L. Hultquist and Mr. Perry M. Waughtal. KMR's compensation committee makes compensation decisions regarding the executive officers of our general partner and its delegate, KMR. Mr. Richard D. Kinder, Mr. James E. Street, Mr. C. Park Shaper and Mr. Steven J. Kean, who are executive officers of KMR, participate in the deliberations of the KMR compensation committee concerning executive officer compensation. None of the members of KMR's compensation committee is or has been one of our officers or employees, and none of our executive officers served during 2011 on a board of directors or compensation committee of another entity which has employed any of the members of KMR's board of directors or compensation committee.

Directors Fees

Awards under our Common Unit Compensation Plan for Non-Employee Directors serve as compensation for each of KMR's three non-employee directors. This plan is described in Note 12 "—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors" to our consolidated financial statements included elsewhere in this report. Directors of KMR who are also employees of Kinder Morgan Kansas, Inc. (Messrs. Richard D. Kinder and C. Park Shaper) do not receive compensation in their capacity as directors.

On April 1, 2003, KMR's compensation committee established our Directors' Unit Appreciation Rights Plan, and pursuant to this plan, each of KMR's then three non-employee directors received common unit appreciation rights. During the first board meeting of 2005, the plan was terminated and replaced by the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors. In December 2011, all remaining 17,500 outstanding unit appreciation rights were exercised. For more information on this plan, see Note 12 "—Directors' Unit Appreciation Rights Plan" to our consolidated financial statements included elsewhere in this report.

The following table discloses the compensation earned by each of KMR's non-employee directors for board service during fiscal year 2011. In addition, directors are reimbursed for reasonable expenses in connection with board meetings.

Name	Fees Earned or Paid in Cash(a)	Common Unit Awards(b)	All Other Compensation(c)	Total
Ted A. Gardner.....	\$ 90,000	\$ -	\$ -	\$ 90,000
Gary L. Hultquist.....	180,000	-	-	180,000
C. Berdon Lawrence.....	1,518	176,964	5,562	184,044
Perry M. Waughtal	180,000	-	203,000	383,000

- (a) Mr. Gardner was elected a KMR director effective July 20, 2011, filling the vacancy left by Mr. Lawrence, who served as a KMR director until his resignation that same day. For Mr. Lawrence, amount represents one-half of the difference between (i) his total cash compensation award and (ii) the value of cash compensation received in the form of our common units (see Note (b)).
- (b) For Mr. Lawrence, amount represents the value of cash compensation received in the form of our common units according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors. Value computed as the number of common units elected to be received in lieu of cash (2,450) multiplied by the closing price on the day cash compensation is approved (\$72.23 on January 18, 2011).
- (c) For Mr. Lawrence, amount represents distributions paid on unvested common units awarded according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors. For Mr. Waughtal, amount represents the unrealized value of common unit appreciation rights earned according to the provisions of our Directors' Unit Appreciation Rights Plan for Non-Employee Directors and determined according to the share-based payment provisions of generally accepted accounting principles— for 17,500 common unit appreciation rights, equal to the increase in value of a corresponding common unit from December 31, 2010 (\$70.26) to his exercise date of December 21, 2011 (\$81.86).

Compensation Committee Report

Throughout fiscal 2011, the compensation committee of KMR's board of directors was comprised of three directors (Mr. Gary L. Hultquist and Mr. Perry M. Waughtal for the full fiscal year, Mr. C. Berdon Lawrence until his resignation

from the compensation committee effective July 20, 2011, and Mr. Ted A. Gardner since replacing Mr. Lawrence on the compensation committee effective July 20, 2011), each of whom the KMR board of directors has determined meets the criteria for independence under KMR's governance guidelines and the New York Stock Exchange rules.

The KMR compensation committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2011 with management. Based on this review and discussion, the KMR compensation committee recommended to its board of directors, that this Compensation Discussion and Analysis be included in this annual report on Form 10-K for the fiscal year 2011.

KMR Compensation Committee:

Ted A. Gardner

Gary L. Hultquist

Perry M. Waughtal

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The following table sets forth information as of January 31, 2012, regarding (i) the beneficial ownership of our common and Class B units and KMR shares by all directors of our general partner and KMR, its delegate, by each of the named executive officers identified in Item 11 "Executive Compensation" and by all directors and executive officers as a group; and (ii) the beneficial ownership of our common and Class B units and KMR shares by all persons known by our general partner to own beneficially at least 5% of such units or shares. Unless otherwise noted, the address of each person below is c/o Kinder Morgan Energy Partners, L.P., 500 Dallas Street, Suite 1000, Houston, Texas 77002.

Name	Amount and Nature of Beneficial Ownership(a)				Kinder Morgan Management Shares	
	Common Units		Class B Units		Number of Shares	Percent of Class(d)
	Number of Units	Percent of Class(b)	Number of Units	Percent of Class(c)		
Richard D. Kinder(e)	315,979	*	-	-	258,368	*
C. Park Shaper	4,000	*	-	-	36,045	*
Ted A. Gardner(f)	43,404	*	-	-	72,765	*
Gary L. Hultquist	1,000	*	-	-	-	-
Perry M. Waughtal	46,918	*	-	-	80,295	*
Steven J. Kean	1,780	*	-	-	2,436	*
Joseph Listengart	5,498	*	-	-	2,728	*
Kimberly A. Dang	121	*	-	-	598	*
Directors and Executive Officers as a group (14 persons)(g)	421,004	*	-	-	465,115	*
Kinder Morgan, Inc.(h)	16,370,428	7.03%	5,313,400	100.00%	14,055,426	14.27%
Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne(i)	-	-	-	-	8,165,754	8.29%

* Less than 1%.

- (a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the units and shares listed.
- (b) As of January 31, 2012, we had 232,837,732 common units issued and outstanding.
- (c) As of January 31, 2012, we had 5,313,400 Class B units issued and outstanding.
- (d) Represent the limited liability company shares of KMR. As of January 31, 2012, there were 98,509,389 issued and outstanding KMR shares, including two voting shares owned by our general partner. In all cases, our i-units will be voted in proportion to the affirmative and negative votes, abstentions and non-votes of owners of KMR shares. Through the provisions in our partnership agreement and KMR's limited liability company agreement, the number of outstanding KMR shares, including voting shares owned by our general partner, and the number of our i-units will at all times be equal.
- (e) Includes 7,879 common units and 1,146 KMR shares owned by Mr. Kinder's spouse. Mr. Kinder disclaims all beneficial and pecuniary interest in these common units and KMR shares.

- (f) Includes 3,607 KMR shares owned by Mr. Gardner's spouse. Mr. Gardner disclaims beneficial ownership in these KMR shares. Also includes 3,968 KMR shares held for one of Mr. Gardner's children.
- (g) Includes 9,090 common units and 4,753 KMR shares owned by executives' spouses and 4,867 KMR shares held by executives and directors for their respective children. The respective executives disclaim any beneficial ownership in 9,090 common units and 4,753 KMR shares.
- (h) Includes common units owned by KMI and its consolidated subsidiaries, including 1,724,000 common units owned by Kinder Morgan G.P., Inc.
- (i) As reported on the Schedule 13G/A filed February 1, 2012 by Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne. Kayne Anderson Capital Advisors, L.P. reported that in regard to KMR shares, it had sole voting power over 0 shares, shared voting power over 8,165,289 shares, sole disposition power over 0 shares and shared disposition power over 8,165,289 shares. Mr. Kayne reports that in regard to KMR shares, he had sole voting power over 465 shares, shared voting power over 8,165,289 shares, sole disposition power over 465 shares and shared disposition power over 8,165,289 shares. Kayne Anderson Capital Advisors, L.P.'s and Richard A. Kayne's address is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067.

KMR's board of directors and its compensation committee previously established a minimum ownership requirement for members of the board with respect to KMP units, KMR shares or a combination thereof. As of December 31, 2011, one member of the board, Mr. Hultquist, did not satisfy this minimum ownership requirement. Effective February 13, 2012, the board, by unanimous consent, determined to provide a waiver of the minimum ownership requirement in the case of Mr. Hultquist until December 31, 2012, or such later date determined by the board.

The following table sets forth as of January 31, 2012, the number of KMI Class P shares, Class A shares, Class B shares and Class C shares of which the individuals listed below have beneficial ownership. The Class A shares, Class B shares and Class C shares are convertible into a fixed aggregate amount of Class P shares under certain circumstances. As of January 31, 2012, there were 170,921,691 Class P shares outstanding, and the Class A shares, Class B shares and Class C shares were convertible into an aggregate of 535,972,387 Class P shares. However, since the Class A shares, Class B shares and Class C shares are convertible into a fixed aggregate number of Class P shares, the conversion of Class B shares and Class C shares into Class P shares will result in a corresponding decrease in the number of Class P shares into which the Class A shares will be able to convert.

Name	Amount and Nature of Beneficial Ownership(a)						KMI Class C Shares	
	KMI Class P Shares		KMI Class A Shares		KMI Class B Shares		Number of Shares	Percent of Class(e)
	Number of Shares	Percent of Class(b)	Number of Shares	Percent of Class(c)	Number of Shares	Percent of Class(d)		
Richard D. Kinder(f)	21,528,167	12.60%	216,538,834	40.40%	37,653,039	40.00%	-	-
C. Park Shaper(g)	1,581,861	*	-	-	10,354,586	11.00%	655,836	28.29%
Ted A. Gardner.....	200,000	*	-	-	-	-	-	-
Gary L. Hultquist	-	-	-	-	-	-	-	-
Perry M. Waughtal	10,000	*	-	-	-	-	-	-
Steven J. Kean.....	884,774	*	-	-	7,530,608	8.00%	322,360	13.91%
Joseph Listengart.....	667,576	*	-	-	3,765,304	4.00%	292,232	12.61%
Kimberly A. Dang(h)	165,549	*	-	-	2,353,315	2.50%	36,172	1.56%
Directors and Executive Officers as a group (14 persons)(i).....	26,665,045	15.60%	216,538,834	40.40%	78,318,322	83.20%	1,789,488	77.19%

* Less than 1%.

- (a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the shares listed.
- (b) As of January 31, 2012, KMI had 170,921,691 Class P shares issued and outstanding.
- (c) As of January 31, 2012, KMI had 535,972,387 Class A shares issued and outstanding.
- (d) As of January 31, 2012, KMI had 94,132,596 Class B shares issued and outstanding.
- (e) As of January 31, 2012, KMI had 2,318,258 Class C shares issued and outstanding.

- (f) Includes 46,664 Class A shares owned by Mr. Kinder's wife. Mr. Kinder disclaims any and all beneficial or pecuniary interest in the Class A units held by his wife. Also includes 551,434 Class P shares and 12,551,013 Class B shares held by a limited partnership of which Mr. Kinder controls the voting and disposition power. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in these shares.
- (g) Includes 97,504 Class P shares and 10,354,586 Class B shares held by a limited partnership of which Mr. Shaper controls the voting and disposition power. Mr. Shaper disclaims 98% and 21% of any beneficial and pecuniary interest in these Class P and Class B shares, respectively.
- (h) Includes 103,394 Class P shares and 2,353,315 Class B shares held by a limited partnership of which Mrs. Dang controls the voting and disposition power. Mrs. Dang disclaims 10% of any beneficial and pecuniary interest in these shares.
- (i) See notes (f), (g) and (h) above. Also includes 115,801 Class P shares and 2,635,713 Class B shares held by a limited partnership of which an executive officer controls the voting and disposition power, but in respect of which shares the executive officer disclaims 8% of any beneficial or pecuniary interest. Also includes 173,701 Class P shares and 3,953,569 Class B shares held by limited partnerships of which an executive officer controls the voting and disposition power but in respect of which shares, the executive officer disclaims 29.4% of any beneficial or pecuniary interest.

Equity Compensation Plan Information

The following table sets forth information regarding our equity compensation plans as of December 31, 2011. Specifically, the table provides information regarding our Common Unit Compensation Plan for Non-Employee Directors, described in Item 11 "Executive Compensation—Director Compensation—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors," and Note 12 to our consolidated financial statements included elsewhere in this report.

Plan Category	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	-
Equity compensation plans not approved by security holders	69,782
Total	69,782

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Related Transactions

Our policy is that (i) employees must obtain authorization from the appropriate business unit president of the relevant company or head of corporate function, and (ii) directors, business unit presidents, executive officers and heads of corporate functions must obtain authorization from the non-interested members of the audit committee of the applicable board of directors, for any business relationship or proposed business transaction in which they or an immediate family member has a direct or indirect interest, or from which they or an immediate family member may derive a personal benefit (a "related party transaction"). When deciding whether to authorize a related party transaction, our business unit presidents and the non-interested members of the audit committee of the applicable board of directors, consider, among other things, the nature of the transaction and the relationship, the dollar amount involved, and the availability of reasonable alternatives.

The maximum dollar amount of related party transactions that may be approved as described above in this paragraph in any calendar year is \$1.0 million. Any related party transactions that would bring the total value of such transactions to greater than \$1.0 million must be referred to the audit committee of the appropriate board of directors for approval or to determine the procedure for approval.

For further information regarding our related party transactions, see Note 11 to our consolidated financial statements included elsewhere in this report.

Director Independence

Our limited partnership agreement provides for us to have a general partner rather than a board of directors. Pursuant to a delegation of control agreement, our general partner delegated to KMR, to the fullest extent permitted under

Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. Through the operation of that agreement and our partnership agreement, KMR manages and controls our business and affairs, and the board of directors of KMR performs the functions of and acts as our board of directors. Similarly, the standing committees of KMR's board of directors function as standing committees of our board. KMR's board of directors is comprised of the same persons who comprise our general partner's board of directors. References in this report to the board mean KMR's board, acting as our board of directors, and references to committees mean KMR's committees, acting as committees of our board of directors.

The board has adopted governance guidelines for the board and charters for the audit committee, nominating and governance committee and compensation committee. The governance guidelines and the rules of the New York Stock Exchange require that a majority of the directors be independent, as described in those guidelines, the committee charters and rules, respectively. Copies of the guidelines and committee charters are available on our internet Website at www.kindermorgan.com.

As described above, each of Mr. Gardner, Mr. Hultquist and Mr. Waughtal is also an independent director of our general partner. Further, each has no family relationship with any of the directors or executive officers of KMR, our general partner or us, and each has no direct or indirect material interest in any transaction or proposed transaction required to be reported under Section 404(a) of Regulation S-K.

The board has affirmatively determined that Messrs. Gardner, Hultquist and Waughtal, who constitute a majority of the directors, are independent as described in our governance guidelines and the New York Stock Exchange rules. In conjunction with all regular quarterly and certain special board meetings, these three non-management directors also meet in executive session without members of management. In January 2012, Mr. Gardner was elected for a one year term to serve as lead director to develop the agendas for and preside at these executive sessions of independent directors.

The governance guidelines and our audit committee charter, as well as the rules of the New York Stock Exchange and the Securities and Exchange Commission, require that members of the audit committee satisfy independence requirements in addition to those above. The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

Item 14. *Principal Accounting Fees and Services*

The following sets forth fees billed for the audit and other services provided by PricewaterhouseCoopers LLP for the fiscal years ended December 31, 2011 and 2010 (in dollars):

	Year Ended December 31,	
	2011	2010
Audit fees(a).....	\$ 2,949,566	\$ 2,797,638
Tax fees(b).....	2,366,165	2,426,521
Total.....	<u>\$ 5,315,731</u>	<u>\$ 5,224,159</u>

- (a) Includes fees for integrated audit of annual financial statements and internal control over financial reporting, reviews of the related quarterly financial statements, and reviews of documents filed with the Securities and Exchange Commission. 2011 and 2010 amounts also include fees of \$643,000 and \$610,000, respectively, for GAAP audits of certain stand-alone financial statements.
- (b) For 2011 and 2010, amounts include fees of \$2,350,480 and \$1,863,233, respectively, billed for professional services rendered for tax processing and preparation of Forms K-1 for our unitholders; and fees of \$15,685 and \$45,405, respectively, billed for professional services rendered for Internal Revenue Service assistance, tax function effectiveness, and for general state, local and foreign tax compliance and consulting services. For 2010 only, amount also includes fees of \$495,000 billed for accounting methods/inventory accounting solutions and fees of \$22,883 billed for self-charged items of interest income and deduction.

All services rendered by PricewaterhouseCoopers LLP are permissible under applicable laws and regulations, and were pre-approved by the audit committee of KMR and our general partner. Pursuant to the charter of the audit committee of KMR, the delegate of our general partner, the committee's primary purposes include the following: (i) to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; (ii) to pre-approve all audit and non-audit services, including tax services, to be provided, consistent with all applicable laws, to us by our external auditors; and (iii) to establish the fees and other compensation to be paid to our external auditors. The audit committee has

reviewed the external auditors' fees for audit and non audit services for fiscal year 2011. The audit committee has also considered whether such non audit services are compatible with maintaining the external auditors' independence and has concluded that they are compatible at this time.

Furthermore, the audit committee will review the external auditors' proposed audit scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, will regularly review with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and will, at least annually, use its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items): (i) the auditors' internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors; (iii) the independence of the external auditors; and (iv) the aggregate fees billed by our external auditors for each of the previous two fiscal years.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

See “Index to Financial Statements” set forth on page 109.

(a)(3) *Exhibits*

- *3.1 —Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended June 30, 2001, filed on August 9, 2001).
- *3.2 —Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed November 22, 2004).
- *3.3 —Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed May 5, 2005).
- *3.4 —Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed April 21, 2008).
- *4.1 —Form of certificate evidencing Common Units representing the common units of Kinder Morgan Energy Partners, L.P. (included as Exhibit A to Third Amended and Restated Agreement of Limited Partnership, filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P.'s quarterly report on Form 10-Q for the quarter ended June 30, 2001 File No. 1701930, filed August 9, 2001).
- *4.2 —Indenture dated as of January 29, 1999 among Kinder Morgan Energy Partners, L.P., the guarantors listed on the signature page thereto and U.S. Trust Company of Texas, N.A., as trustee, relating to Senior Debt Securities (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed February 16, 1999, File No. 1-11234 (the “February 16, 1999 Form 8-K”)).
- *4.3 —Indenture dated November 8, 2000 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as Trustee (filed as Exhibit 4.8 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2001 (File No. 1-11234)).
- *4.4 —Indenture dated January 2, 2001 between Kinder Morgan Energy Partners 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. Form 10-K (File No. 1-11234) for 2000).
- *4.5 —Indenture dated January 2, 2001 between Kinder Morgan Energy Partners and First Union National Bank, as trustee, relating to Subordinated Debt Securities (including form of Subordinated Debt Securities) (filed as Exhibit 4.12 to Kinder Morgan Energy Partners, L.P. Form 10-K (File No. 1-11234) for 2000).
- *4.6 —Certificate of 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. Form 8-K (File No. 1-11234), filed on March 14, 2001).
- *4.7 —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. Form 8-K (File No. 1-11234), filed on March 14, 2001).
- *4.8 —Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.125% Notes due March 15, 2012 and the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

- *4.9 —Specimen of 7.125% Notes due March 15, 2012 in book-entry form (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).
- *4.10 —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. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).
- *4.11 —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 the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 (File No. 333-100346) filed on October 4, 2002 (the “October 4, 2002 Form S-4”)).
- *4.12 —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 the October 4, 2002 Form S-4).
- *4.13 —Form of 7.30% Note (contained in the Indenture filed as Exhibit 4.1 to the October 4, 2002 Form S-4 (File No. 333-102961)).
- *4.14 —Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 (File No. 333-102961) filed on February 4, 2003 (the “February 4, 2003 Form S-3”)).
- *4.15 —Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to the February 4, 2003 Form S-3).
- *4.16 —Subordinated Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.4 to the February 4, 2003 Form S-3).
- *4.17 —Form of Subordinated Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Subordinated Indenture filed as Exhibit 4.4 to the February 4, 2003 Form S-3 (File No. 333-102961)).
- *4.18 —Certificate of Vice President, Treasurer and Chief Financial Officer and 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 5.00% Notes due December 15, 2013 (filed as Exhibit 4.25 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004 (File No. 001-11234)).
- *4.19 —Certificate of Executive Vice President and Chief Financial Officer and 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 5.125% Notes due November 15, 2014 (filed as Exhibit 4.27 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2004 filed March 4, 2005 (File No. 1-11234)).
- *4.20 —Certificate of Vice President, Treasurer and Chief Financial Officer and 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. Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005 (File No. 1-11234)).
- *4.21 —Certificate of 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 February 1, 2017 and 6.50% Senior Notes due February 1, 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2006 filed March 1, 2007).
- *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 6.95% Senior Notes due January 15, 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2007 filed August 8, 2007).

- *4.23 —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 5.85% Senior Notes due September 15, 2012 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2007 filed November 9, 2007).
- *4.24 —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 5.95% Senior Notes due February 15, 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2007 filed February 26, 2008).
- *4.25 —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 February 1, 2019 (filed as Exhibit 4.29 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2008 filed February 23, 2009).
- *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 5.625% Senior Notes due February 15, 2015, and the 6.85% Senior Notes due February 15, 2020 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2009 filed August 3, 2009).
- *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 5.80% Senior Notes due March 1, 2021, and the 6.50% Senior Notes due September 1, 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2009 filed October 30, 2009).
- *4.28 —Registration Rights Agreement, dated as of January 15, 2010, between US Development Group LLC and Kinder Morgan Energy Partners, L.P. (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed January 19, 2010).
- *4.29 —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 September 15, 2020, and the 6.55% Senior Notes due September 15, 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2010 filed July 30, 2010).
- *4.30 —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 3.50% Senior Notes due March 1, 2016, and the 6.375% Senior Notes due March 1, 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended March 31, 2011 filed April 29, 2011).
- *4.31 —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 4.15% Senior Notes due March 1, 2022, and the 5.625% Senior Notes due September 1, 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011).
- 4.32 —Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. 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. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
- *10.1 —Delegation of Control Agreement among Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001 (File No. 1-11234)).

- *10.2 —Amendment No. 1 to Delegation of Control Agreement, dated as of July 20, 2007, among Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K on July 20, 2007).
- *10.3 —Kinder Morgan Energy Partners, L.P. Directors’ Unit Appreciation Rights Plan (filed as Exhibit 10.6 to the Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004 (File No. 1-11234)).
- *10.4 —Amendment No. 1 to Kinder Morgan Energy Partners, L.P. Directors’ Unit Appreciation Rights Plan (filed as Exhibit 10.7 to the Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004 (File No. 1-11234)).
- *10.5 —Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors (filed as Exhibit 10.2 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005 (File No. 1-11234)).
- *10.6 —Form of Common Unit Compensation Agreement entered into with Non-Employee Directors (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005 (File No. 1-11234)).
- *10.7 —Three-Year Credit Agreement dated as of June 23, 2010 among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. “B”, the lenders party thereto, Wells Fargo Bank, National Association as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A., and DnB NOR Bank ASA (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.’s Current Report on Form 8-K, filed on June 24, 2010).
- *10.8 —First Amendment to Credit Agreement, dated as of July 1, 2011, among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. “B”, the lenders party thereto and Wells Fargo Bank, National Association as Administrative Agent (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2011 (File No. 1-11234)).
- *10.9 —Kinder Morgan, Inc. 2011 Stock Incentive Plan (filed as Exhibit 10.1 to Kinder Morgan, Inc.’s Form 10-Q for the quarter ended March 31, 2011 (File No. 1-35081) (the “KMI 10-Q”)).
- *10.10 —Form of Restricted Stock Agreement (filed as Exhibit 10.2 to the KMI 10-Q).
- *10.11 —Kinder Morgan, Inc. Employee Stock Purchase Plan (filed as Exhibit 10.5 to the KMI 10-Q).
- *10.12 —Kinder Morgan, Inc. Annual Incentive Plan (filed as Exhibit 10.6 to the KMI 10-Q).
- *10.13 —Severance Agreement with C. Park Shaper (filed as Exhibit 10.7 to the KMI 10-Q).
- *10.14 —Severance Agreement with Steven J. Kean (filed as Exhibit 10.8 to the KMI 10-Q).
- *10.15 —Severance Agreement with Kimberly A. Dang (filed as Exhibit 10.9 to the KMI 10-Q).
- *10.16 —Severance Agreement with Joseph Listengart (filed as Exhibit 10.10 to the KMI 10-Q).
- 11.1 —Statement re: computation of per share earnings.
- 12.1 —Statement re: computation of ratio of earnings to fixed charges.
- 21.1 —List of Subsidiaries.
- 23.1 —Consent of PricewaterhouseCoopers LLP.
- 23.2 —Consent of Netherland, Sewell and Associates, Inc.
- 31.1 —Certification by CEO 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 by CFO 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 by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 —Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 95.1 —Mine Safety Disclosures.
- 99.1 —Estimates of the net reserves and future net revenues, as of December 31, 2011, related to Kinder Morgan CO₂ Company, L.P.'s interest in certain oil and gas properties located in the state of Texas.
- 101 —Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009; (iii) our Consolidated Balance Sheets as of December 31, 2011 and 2010; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; (v) our Consolidated Statements of Partners' Capital for the years ended December 31, 2011, 2010 and 2009; 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.

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Report of Independent Registered Public Accounting Firm

To the Partners of
Kinder Morgan Energy Partners, L.P.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these 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 in Item 9A of the Partnership's 2011 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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 17, 2012

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	2010	2009
	(In millions except per unit amounts)		
Revenues			
Natural gas sales	\$ 3,335.8	\$ 3,614.4	\$ 3,137.2
Services	3,108.7	3,024.7	2,739.1
Product sales and other	1,766.7	1,438.6	1,127.1
Total Revenues	<u>8,211.2</u>	<u>8,077.7</u>	<u>7,003.4</u>
Operating Costs, Expenses and Other			
Gas purchases and other costs of sales	3,400.8	3,606.3	3,068.8
Operations and maintenance	1,539.4	1,415.0	1,136.2
Depreciation, depletion and amortization	954.5	904.8	850.8
General and administrative	472.7	375.2	330.3
Taxes, other than income taxes	184.2	171.4	137.0
Other expense (income)	(10.9)	(0.1)	(34.8)
Total Operating Costs, Expenses and Other	<u>6,540.7</u>	<u>6,472.6</u>	<u>5,488.3</u>
Operating Income	1,670.5	1,605.1	1,515.1
Other Income (Expense)			
Earnings from equity investments	311.1	223.1	189.7
Amortization of excess cost of equity investments	(6.7)	(5.8)	(5.8)
Interest expense	(533.9)	(507.6)	(431.5)
Interest income	22.9	22.7	22.5
Loss on remeasurement of previously held equity interest in KinderHawk (Note 3)	(167.2)	-	-
Other, net	17.5	24.2	49.5
Total Other Income (Expense)	<u>(356.3)</u>	<u>(243.4)</u>	<u>(175.6)</u>
Income Before Income Taxes	1,314.2	1,361.7	1,339.5
Income Tax (Expense) Benefit	<u>(45.8)</u>	<u>(34.6)</u>	<u>(55.7)</u>
Net Income	1,268.4	1,327.1	1,283.8
Net Income Attributable to Noncontrolling Interests	<u>(10.6)</u>	<u>(10.8)</u>	<u>(16.3)</u>
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	<u>\$ 1,257.8</u>	<u>\$ 1,316.3</u>	<u>\$ 1,267.5</u>
Calculation of Limited Partners' Interest in Net Income Attributable to Kinder Morgan Energy Partners, L.P.:			
Net Income Attributable to Kinder Morgan Energy Partners, L.P. .	\$ 1,257.8	\$ 1,316.3	\$ 1,267.5
Less: General Partner's Interest	<u>(1,175.0)</u>	<u>(884.9)</u>	<u>(935.8)</u>
Limited Partners' Interest in Net Income	<u>\$ 82.8</u>	<u>\$ 431.4</u>	<u>\$ 331.7</u>
Limited Partners' Net Income per Unit	<u>\$ 0.25</u>	<u>\$ 1.40</u>	<u>\$ 1.18</u>
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	<u>326.1</u>	<u>307.1</u>	<u>281.5</u>
Per Unit Cash Distribution Declared	<u>\$ 4.61</u>	<u>\$ 4.40</u>	<u>\$ 4.20</u>

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Net Income	\$ 1,268.4	\$ 1,327.1	\$ 1,283.8
Other Comprehensive Income (Loss):			
Change in fair value of derivatives utilized for hedging purposes.....	14.1	(76.1)	(458.2)
Reclassification of change in fair value of derivatives to net income.....	255.3	188.4	100.3
Foreign currency translation adjustments.....	(44.4)	100.6	252.2
Adjustments to pension and other postretirement benefit plan liabilities	(33.5)	(2.3)	(2.5)
Total Other Comprehensive Income (Loss)	<u>191.5</u>	<u>210.6</u>	<u>(108.2)</u>
Comprehensive Income	1,459.9	1,537.7	1,175.6
Comprehensive Income Attributable to Noncontrolling Interests.....	(12.4)	(13.0)	(15.2)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	<u>\$ 1,447.5</u>	<u>\$ 1,524.7</u>	<u>\$ 1,160.4</u>

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2011	2010
	(Dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents.....	\$ 409.3	\$ 129.1
Restricted deposits	-	50.0
Accounts, notes and interest receivable, net.....	883.5	951.8
Inventories.....	109.8	92.0
Gas in underground storage.....	61.8	2.2
Fair value of derivative contracts	71.4	24.0
Other current assets	39.6	37.6
Total current assets.....	1,575.4	1,286.7
Property, plant and equipment, net	15,595.8	14,603.9
Investments	3,346.2	3,886.0
Notes receivable.....	165.0	115.0
Goodwill	1,436.2	1,233.6
Other intangibles, net.....	1,152.0	302.2
Fair value of derivative contracts.....	632.0	260.7
Deferred charges and other assets	200.1	173.0
Total Assets.....	\$ 24,102.7	\$ 21,861.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt.....	\$ 1,637.8	\$ 1,262.4
Cash book overdrafts.....	20.9	32.5
Accounts payable	706.5	630.9
Accrued interest	258.6	239.6
Accrued taxes	38.1	44.7
Deferred revenues	99.5	96.6
Fair value of derivative contracts	120.8	281.5
Accrued other current liabilities	236.9	176.0
Total current liabilities	3,119.1	2,764.2
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding.....	11,159.5	10,277.4
Value of interest rate swaps	1,078.9	604.9
Total long-term debt	12,238.4	10,882.3
Deferred income taxes.....	249.6	248.3
Fair value of derivative contracts	38.7	172.2
Other long-term liabilities and deferred credits.....	853.0	501.6
Total long-term liabilities and deferred credits	13,379.7	11,804.4
Total Liabilities.....	16,498.8	14,568.6
Commitments and contingencies (Notes 8, 12 and 16)		
Partners' Capital		
Common units (232,677,222 and 218,880,103 units issued and outstanding as of December 31, 2011 and 2010, respectively)	4,346.9	4,282.2
Class B units (5,313,400 and 5,313,400 units issued and outstanding as of December 31, 2011 and 2010, respectively)	41.5	63.1
i-units (98,509,389 and 91,907,987 units issued and outstanding as of December 31, 2011 and 2010, respectively)	2,857.2	2,807.5
General partner.....	258.7	244.3
Accumulated other comprehensive income (loss)	3.3	(186.4)
Total Kinder Morgan Energy Partners, L.P.'s partners' capital	7,507.6	7,210.7
Noncontrolling interests	96.3	81.8
Total Partners' Capital.....	7,603.9	7,292.5
Total Liabilities and Partners' Capital.....	\$ 24,102.7	\$ 21,861.1

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Cash Flows From Operating Activities			
Net Income	\$ 1,268.4	\$ 1,327.1	\$ 1,283.8
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	954.5	904.8	850.8
Amortization of excess cost of equity investments	6.7	5.8	5.8
Loss on remeasurement of previously held equity interest in KinderHawk (Note 3).....	167.2	-	-
Noncash compensation expense allocated from KMI (Note 11).....	89.9	4.6	5.7
Earnings from equity investments.....	(311.1)	(223.1)	(189.7)
Distributions from equity investments.....	286.6	219.8	234.5
Proceeds from termination of interest rate swap agreements.....	73.0	157.6	144.4
Changes in components of working capital:			
Accounts receivable	14.1	17.7	54.5
Inventories	17.6	(20.8)	(20.0)
Other current assets.....	(60.5)	31.6	(75.9)
Accounts payable.....	38.1	(9.4)	(184.6)
Cash book overdrafts	(11.5)	(2.2)	(8.0)
Accrued interest.....	19.0	17.1	50.2
Accrued taxes.....	(9.2)	(12.9)	5.3
Accrued liabilities	0.1	12.8	(24.1)
Rate reparations, refunds and other litigation reserve adjustments.....	170.4	(34.3)	2.5
Other, net.....	160.5	20.6	(26.1)
Net Cash Provided by Operating Activities	2,873.8	2,416.8	2,109.1
Cash Flows From Investing Activities			
Acquisitions of investments.....	(970.6)	(925.7)	(36.0)
Acquisitions of assets	(208.1)	(287.5)	(292.9)
Repayments from related party.....	31.3	2.7	3.7
Repayments from customers.....	-	-	109.6
Capital expenditures	(1,199.5)	(1,000.9)	(1,323.8)
Sale or casualty of property, plant and equipment, investments and other net assets, net of removal costs	25.0	34.3	47.4
Net proceeds from (Investments in) margin and restricted deposits	57.7	(32.2)	(18.5)
Contributions to investments	(371.0)	(299.3)	(2,051.8)
Distributions from equity investments in excess of cumulative earnings	214.7	189.8	112.0
Other, net.....	3.6	7.2	0.2
Net Cash Used in Investing Activities.....	(2,416.9)	(2,311.6)	(3,450.1)
Cash Flows From Financing Activities			
Issuance of debt.....	7,501.9	7,140.1	6,891.9
Payment of debt.....	(6,393.7)	(6,186.4)	(4,857.1)
Debt issue costs	(17.7)	(22.9)	(13.7)
Proceeds from issuance of common units.....	955.3	758.7	1,155.6
Contributions from noncontrolling interests.....	29.1	12.5	15.4
Distributions to partners and noncontrolling interests:			
Common units.....	(1,029.9)	(918.7)	(809.2)
Class B units	(24.4)	(22.9)	(22.3)
General Partner	(1,161.4)	(861.7)	(918.4)
Noncontrolling interests.....	(27.9)	(23.3)	(22.0)
Other, net.....	(0.4)	(0.4)	(1.1)
Net Cash (Used in) Provided by Financing Activities.....	(169.1)	(125.0)	1,419.1
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(7.6)	2.3	6.0
Net increase (decrease) in Cash and Cash Equivalents	280.2	(17.5)	84.1
Cash and Cash Equivalents, beginning of period	129.1	146.6	62.5
Cash and Cash Equivalents, end of period	\$ 409.3	\$ 129.1	\$ 146.6

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

	Year Ended December 31,		
	2011	2010	2009
	(In millions)		
Noncash Investing and Financing Activities			
Assets acquired by the assumption or incurrence of liabilities.....	\$ 206.5	\$ 13.8	\$ 7.7
Assets acquired by the issuance of common units	\$ 23.7	\$ 81.7	\$ 5.0
Assets acquired by the issuance of note	\$ 2.1	\$ -	\$ -
Contribution of net assets to investments	\$ 7.9	\$ 20.0	\$ -
Sale of investment ownership interest in exchange for note	\$ 4.1	\$ -	\$ -
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest).....	\$ 518.0	\$ 472.8	\$ 400.3
Cash paid (received) during the period for income taxes	\$ 10.0	\$ (2.2)	\$ 3.4

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	2011		2010		2009	
	Units	Amount	Units	Amount	Units	Amount
	(Dollars in millions)					
Common units:						
Beginning Balance.....	218,880,103	\$ 4,282.2	206,020,826	\$ 4,057.9	182,969,427	\$ 3,458.9
Net income.....	-	56.9	-	299.5	-	229.0
Units issued as consideration pursuant to common unit compensation plan for non-employee directors.....	2,450	0.2	2,450	0.2	3,200	0.2
Units issued as consideration in the acquisition of assets	324,961	23.7	1,287,287	81.7	105,752	5.0
Units issued for cash.....	13,469,708	955.3	11,569,540	758.7	22,942,447	1,155.6
Adjustments to capital resulting from related party acquisitions.....	-	-	-	-	-	15.5
Distributions	-	(1,029.9)	-	(918.7)	-	(809.2)
Noncash compensation expense allocated from KMI ..	-	60.8	-	3.3	-	3.9
Other adjustments	-	(2.3)	-	(0.4)	-	(1.0)
Ending Balance.....	232,677,222	4,346.9	218,880,103	4,282.2	206,020,826	4,057.9
Class B units:						
Beginning Balance.....	5,313,400	63.1	5,313,400	78.6	5,313,400	94.0
Net income.....	-	1.3	-	7.4	-	6.3
Adjustments to capital resulting from related party acquisitions	-	-	-	-	-	0.5
Distributions	-	(24.4)	-	(22.9)	-	(22.3)
Noncash compensation expense allocated from KMI ..	-	1.5	-	-	-	0.1
Other adjustments	-	-	-	-	-	-
Ending Balance.....	5,313,400	41.5	5,313,400	63.1	5,313,400	78.6
i-units:						
Beginning Balance.....	91,907,987	2,807.5	85,538,263	2,681.7	77,997,906	2,577.1
Net income.....	-	24.6	-	124.5	-	96.4
Adjustments to capital resulting from related party Acquisitions.....	-	-	-	-	-	6.6
Distributions	6,601,402	-	6,369,724	-	7,540,357	-
Noncash compensation expense allocated from KMI ..	-	25.8	-	1.3	-	1.6
Other adjustments	-	(0.7)	-	-	-	-
Ending Balance.....	98,509,389	2,857.2	91,907,987	2,807.5	85,538,263	2,681.7
General partner:						
Beginning Balance.....	-	244.3	-	221.1	-	203.3
Net income.....	-	1,175.0	-	884.9	-	935.8
Adjustments to capital resulting from related party Acquisitions.....	-	-	-	-	-	0.3
Distributions	-	(1,161.4)	-	(861.7)	-	(918.4)
Noncash compensation expense allocated from KMI ..	-	0.9	-	-	-	0.1
Other adjustments	-	(0.1)	-	-	-	-
Ending Balance.....	-	258.7	-	244.3	-	221.1
Accumulated other comprehensive income (loss):						
Beginning Balance.....	-	(186.4)	-	(394.8)	-	(287.7)
Change in fair value of derivatives utilized for hedging purposes	-	14.0	-	(75.3)	-	(453.6)
Reclassification of change in fair value of derivatives to net income.....	-	252.8	-	186.5	-	99.3
Foreign currency translation adjustments.....	-	(44.0)	-	99.5	-	249.7
Adjustments to pension and other postretirement benefit plan liabilities.....	-	(33.1)	-	(2.3)	-	(2.5)
Ending Balance.....	-	3.3	-	(186.4)	-	(394.8)
Total Kinder Morgan Energy Partners, L.P. partners' capital.....	336,500,011	\$ 7,507.6	316,101,490	\$ 7,210.7	296,872,489	\$ 6,644.5

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (continued)

	2011		2010		2009	
	Units	Amount	Units	Amount	Units	Amount
	(Dollars in millions)					
Noncontrolling interests:						
Beginning Balance.....	-	\$ 81.8	-	\$ 79.6	-	\$ 70.7
Net income.....	-	10.6	-	10.8	-	16.3
Adjustments to capital resulting from related party						
Acquisitions	-	-	-	-	-	0.3
Contributions	-	29.1	-	12.5	-	15.4
Distributions	-	(27.9)	-	(23.3)	-	(22.0)
Change in fair value of derivatives utilized for						
hedging purposes	-	0.1	-	(0.8)	-	(4.6)
Reclassification of change in fair value of derivatives						
to net income.....	-	2.5	-	1.9	-	1.0
Foreign currency translation adjustments.....	-	(0.4)	-	1.1	-	2.5
Adjustments to pension and other postretirement						
benefit plan liabilities.....	-	(0.4)	-	-	-	-
Noncash compensation expense allocated from KMI ..	-	0.9	-	-	-	-
Ending Balance.....	-	96.3	-	81.8	-	79.6
Total Partners' Capital	<u>336,500,011</u>	<u>\$ 7,603.9</u>	<u>316,101,490</u>	<u>\$ 7,292.5</u>	<u>296,872,489</u>	<u>\$ 6,724.1</u>

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

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a Delaware limited partnership formed in August 1992. Unless the context requires otherwise, references to “we,” “us,” “our,” “KMP,” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We own and manage a diversified portfolio of energy transportation and storage assets and presently conduct our business through five reportable business segments.

These segments and the activities performed to provide services to our customers and create value for our unitholders are as follows:

- Products Pipelines - transporting, storing and processing refined petroleum products;
- Natural Gas Pipelines - transporting, storing, buying, selling, gathering, treating and processing natural gas;
- CO₂ – transporting oil, producing, transporting and selling carbon dioxide, commonly called CO₂, for use in, and selling crude oil, natural gas and natural gas liquids produced from, enhanced oil recovery operations;
- Terminals - transloading, storing and delivering a wide variety of bulk, petroleum, petrochemical and other liquid products at terminal facilities located across the United States and portions of Canada; and
- Kinder Morgan Canada – transporting crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, and owning a one-third interest in an integrated oil transportation network that connects Canadian and United States producers to refineries in the U.S. Rocky Mountain and Midwest regions.

We focus on providing fee-based services to customers, generally avoiding near-term commodity price risks and taking advantage of the tax benefits of a limited partnership structure. We trade on the New York Stock Exchange under the symbol “KMP,” and we conduct our operations through the following five limited partnerships: (i) Kinder Morgan Operating L.P. “A”; (ii) Kinder Morgan Operating L.P. “B”; (iii) Kinder Morgan Operating L.P. “C”; (iv) Kinder Morgan Operating L.P. “D”; and (v) Kinder Morgan CO₂ Company, L.P. Combined, the five limited partnerships are referred to as our operating partnerships, and we are the 98.9899% limited partner and our general partner is the 1.0101% general partner in each. Both we and our operating partnerships are governed by Amended and Restated Agreements of Limited Partnership, as amended, and certain other agreements that are collectively referred to in this report as the partnership agreements.

Kinder Morgan, Inc., Kinder Morgan Kansas, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation and referred to as KMI in this report, indirectly owns all the common stock of Kinder Morgan Kansas, Inc. Kinder Morgan Kansas, Inc. is a Kansas corporation and indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation. In July 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calneve Pipe Line LLC. As of December 31, 2011, KMI and its consolidated subsidiaries owned, through KMI’s general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 12.4% interest in us.

Prior to May 30, 2007, Kinder Morgan Kansas, Inc. was known as Kinder Morgan, Inc., and on that date, it merged with a wholly-owned subsidiary of its parent, Knight Holdco LLC, a private company owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of both our general partner and Kinder Morgan Management, LLC. This merger is referred to in this report as the going-private transaction, and following the merger, Kinder Morgan, Inc. (the surviving legal entity from the merger) was renamed Knight, Inc. On July 15, 2009, Knight Inc. changed its name back to Kinder Morgan, Inc., and subsequently, Knight Holdco LLC was renamed Kinder Morgan Holdco LLC.

On November 23, 2010, Kinder Morgan Holdco LLC filed a registration statement on Form S-1 with the Securities and Exchange Commission for a proposed initial public offering of its common stock. The registration statement became effective on February 10, 2011. In connection with the offering, Kinder Morgan Holdco LLC converted from a Delaware limited liability company to a Delaware corporation named Kinder Morgan, Inc. (KMI), and the former Kinder Morgan, Inc. was renamed Kinder Morgan Kansas, Inc. On February 11, 2011, KMI's common stock began trading on the New York Stock Exchange under the symbol "KMI," and on February 16, 2011, the initial public offering closed. All of the common stock that was sold in the offering was sold by existing investors, consisting of funds advised by or affiliated with Goldman, Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC. KMI did not receive any proceeds from the offering.

On October 16, 2011, KMI and El Paso Corporation announced a definitive agreement whereby KMI will acquire all of the outstanding shares of El Paso in a transaction that would, as of the announcement date, create an energy company that would have an enterprise value of approximately \$94 billion and would own an interest in approximately 80,000 miles of pipelines. As of the announcement date, the total purchase price, including the assumption of debt outstanding at both El Paso Corporation and El Paso Pipeline Partners, L.P., was approximately \$38 billion. El Paso Corporation owns a 42% limited partner interest and the 2% general partner interest in El Paso Pipeline Partners, L.P. The transaction is expected to close in the second quarter of 2012 and is subject to customary regulatory approvals.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company that was formed on February 14, 2001. Its shares represent limited liability company interests and are traded on the New York Stock Exchange under the symbol "KMR." Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner.

Under the delegation of control agreement, KMR manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their subsidiaries. As of December 31, 2011, KMR owned approximately 29.3% of our outstanding limited partner units (which are in the form of i-units that are issued only to KMR).

2. Summary of Significant Accounting Policies

Basis of Presentation

Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C\$.

Our accompanying consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries, and we have prepared these consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. These rules and regulations conform to the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America. 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. In this report, we refer to the Financial Accounting Standards Board as the FASB and the FASB Accounting Standards Codification as the Codification.

Additionally, our financial statements are consolidated into the consolidated financial statements of KMI; however, our financial statements reflect amounts on a historical cost basis, and, accordingly, do not reflect any purchase accounting adjustments related to KMI's May 30, 2007 going-private transaction (discussed above in Note 1). Also, except for the related party transactions described in Note 11 "Related Party Transactions—Asset Acquisitions and Sales," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

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 disclosure of 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.

In addition, we believe that 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

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

Restricted Deposits

As of December 31, 2011 none of our cash was set aside or restricted for some special purpose. Cash held in escrow is restricted cash, and as of December 31, 2010, we deposited \$50.0 million into a third-party escrow account to comply with contractual stipulations related to our purchase of an initial equity investment in Watco Companies, LLC. We reported this amount separately as “Restricted deposits” on our accompanying consolidated balance sheet. In January 2011, the funds were released from escrow and we used the cash for our investment. For additional information on this investment, see Note 6 “Investments.”

Accounts Receivable

The amounts reported as “Accounts, notes and interest receivable, net” on our accompanying consolidated balance sheets as of December 31, 2011 and 2010 primarily consist of amounts due from third party payors (unrelated entities). For information on receivables due to us from related parties, see Note 11.

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 following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2011, 2010 and 2009 (in millions):

<u>Allowance for doubtful accounts</u>	Valuation and Qualifying Accounts				<u>Deductions(a)</u>	<u>Balance at end of period</u>
	<u>Balance at beginning of period</u>	<u>Additions charged to costs and expenses</u>	<u>Additions charged to other accounts</u>			
Year ended December 31, 2011.....	\$ 6.8	\$ 0.2	\$ -	\$ (1.2)	\$ 5.8	
Year ended December 31, 2010.....	\$ 5.4	\$ 2.3	\$ -	\$ (0.9)	\$ 6.8	
Year ended December 31, 2009.....	\$ 6.1	\$ 0.5	\$ -	\$ (1.2)	\$ 5.4	

(a) Deductions represent the write-off of receivables and currency translation adjustments.

In addition, the balances of “Accrued other current liabilities” in our accompanying consolidated balance sheets include amounts related to customer prepayments of approximately \$5.6 million as of December 31, 2011 and \$7.1 million as of December 31, 2010.

Notes Receivable

The amounts reported as “Notes receivable” on our accompanying consolidated balance sheets as of December 31, 2011 and 2010 primarily consist of amounts due from related parties. For more information about these amounts, see Note 11 “Related Party Transactions—Notes Receivable.”

Inventories

Our inventories of products consist of natural gas liquids, refined petroleum products, natural gas, carbon dioxide and coal. We report these assets at the lower of weighted-average cost or market.

As of December 31, 2011 and 2010, the value of natural gas in our underground storage facilities under the weighted-average cost method was \$61.8 million and \$2.2 million, respectively, and we reported these amounts separately as “Gas in underground storage” in our accompanying consolidated balance sheets. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Gas Imbalances

We value gas imbalances due to or due from interconnecting pipelines at the lower of cost or market, per our quarterly imbalance valuation procedures. Gas imbalances represent the difference between customer nominations and actual gas receipts from, and gas deliveries to, our interconnecting pipelines and shippers under various operational balancing and shipper imbalance agreements. Natural gas imbalances are either settled in cash or made up in-kind subject to the pipelines’ various tariff provisions. As of both December 31, 2011 and 2010, our gas imbalance receivables—including both trade and related party receivables—totaled \$18.8 million, and we included these amounts within “Other current assets” on our accompanying consolidated balance sheets. As of December 31, 2011 and 2010, our gas imbalance payables—including both trade and related party payables—totaled \$9.7 million and \$7.7 million, respectively, and we included these amounts within “Accrued other current liabilities” on our accompanying consolidated balance sheets.

Property, Plant and Equipment

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for maintenance and repairs in the period incurred. As discussed below, for assets used in our oil and gas producing activities or in our unregulated bulk and liquids terminal activities, the cost of property, plant and equipment sold or retired and the related depreciation are removed from our balance sheet in the period of sale or disposition, and we record any related gains and losses from sales or retirements to income or expense accounts. For our pipeline system assets, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. We do not include retirement gain or loss in income except in the case of significant retirements or sales. Gains and losses on minor system sales, excluding land, are recorded to the appropriate accumulated depreciation reserve. Gains and losses for operating systems sales and land sales are booked to income or expense accounts in accordance with regulatory accounting guidelines.

We generally compute depreciation using the straight-line method based on estimated economic lives; however, for certain depreciable assets, we employ the composite depreciation method, applying 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 1.6% to 12.5%, excluding certain short-lived assets such as vehicles. Depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates included changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. However, 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.

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.

In addition, we engage in enhanced recovery techniques in which carbon dioxide is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the carbon dioxide associated with enhanced recovery is capitalized as part of our development costs when it is injected. The acquisition cost associated with pressure maintenance operations for reservoir management is expensed when it is injected. When carbon dioxide 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. The units-of-production rate is determined by field.

As discussed in “—Inventories” above, we own and maintain natural gas in underground storage as part of our inventory. This component of our inventory represents the portion of gas stored in an underground storage facility generally known as working gas, and represents an estimate of the portion of gas in these facilities available for routine injection and withdrawal. In addition to this working gas, underground gas storage reservoirs contain injected gas which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow efficient operation of the facility. This gas, generally known as cushion gas, is divided into the categories of recoverable cushion gas and unrecoverable cushion gas, based on an engineering analysis of whether the gas can be economically removed from the storage facility at any point during its life. The portion of the cushion gas that is determined to be unrecoverable is considered to be a permanent part of the facility itself (thus, part of our “Property, plant and equipment, net” balance in our accompanying consolidated balance sheets), and this unrecoverable portion is depreciated over the facility’s estimated useful life. The portion of the cushion gas that is determined to be recoverable is also considered a component of the facility but is not depreciated because it is expected to ultimately be recovered and sold.

Impairments

We measure long-lived assets that are to be disposed of by sale at the lower of book value or fair value less the cost to sell, and we review for the impairment of long-lived assets whenever events or changes in circumstances indicate that our carrying amount of an asset may not be recoverable. We would recognize an impairment loss when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

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 and possible reserves. For the purpose of impairment testing, adjustments for the inclusion of risk-adjusted probable and possible reserves, as well as forward curve pricing, will cause impairment calculation cash flows to differ from the amounts presented in our supplemental information on oil and gas producing activities disclosed in Note 20.

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.

Allowance for Funds Used During Construction/Capitalized Interest

Included in the cost of our qualifying property, plant and equipment is (i) an allowance for funds used during construction (AFUDC) or upgrade for assets regulated by the Federal Energy Regulatory Commission; or (ii) capitalized interest. The primary difference between AFUDC and capitalized interest is that AFUDC may include a component for equity funds, while capitalized interest does not. AFUDC on debt, as well as capitalized interest, represents the estimated cost of capital, from borrowed funds, during the construction period that is not immediately expensed, but instead is treated as an asset (capitalized) and amortized to expense over time in our income statements. Total AFUDC on debt and

capitalized interest in 2011, 2010 and 2009 was \$14.5 million, \$12.5 million and \$32.9 million, respectively. Similarly, AFUDC on equity represents an estimate of the cost of capital funded by equity contributions, and in the years ended December 31, 2011, 2010 and 2009, we also capitalized \$0.2 million, \$0.7 million and \$22.7 million, respectively, of equity AFUDC.

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, 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. For more information on our asset retirement obligations, see Note 5 “Property, Plant and Equipment—Asset Retirement Obligations.”

Equity Method of Accounting

We account for investments—which we do not control but do have the ability to exercise significant influence—by 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.

Goodwill

Goodwill represents the excess of the cost of an acquisition price over the fair value of acquired net assets, and such amounts are reported separately as “Goodwill” on our accompanying consolidated balance sheets. Our total goodwill was \$1,436.2 million as of December 31, 2011, and \$1,233.6 million as of December 31, 2010. Goodwill cannot be amortized, but instead 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 perform our goodwill impairment test on May 31 of each year. There were no impairment charges resulting from our May 31, 2011, 2010 or 2009 impairment testing, and no event indicating an impairment has occurred subsequent to May 31, 2011.

If a significant portion of one of our business segments is disposed of (that also constitutes a business), we would allocate goodwill based on the relative fair values of the portion of the segment being disposed of and the portion of the segment remaining. We would then perform an impairment test of the goodwill in the remaining portion of the segment after the goodwill allocation to ensure that the segment could support the remaining goodwill. For more information on our goodwill, see Note 7.

Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We generally sell natural gas under long-term agreements, generally based on Houston Ship Channel index posted prices. In some cases, we sell natural gas under short-term agreements at prevailing market prices. In all cases, we recognize natural gas sales revenues when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The natural gas we market is primarily purchased gas produced by third parties, and we market this gas to power generators, local distribution companies, industrial end-users and national marketing companies. We recognize gas gathering and marketing revenues in the month of delivery based on customer nominations and generally, our natural gas marketing revenues are recorded gross, not net of cost of gas sold.

In addition to storing and transporting a significant portion of the natural gas volumes we purchase and resell, we provide various types of natural gas storage and transportation services for third-party customers. The natural gas remains the property of these customers at all times. In many cases, generally described as firm service, the customer pays a two-part rate that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities; and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers’ agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities.

In other cases, generally described as interruptible service, there is no fixed fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements. In addition to our firm and interruptible transportation services, we also provide natural gas balancing services to assist customers in managing short-term gas surpluses or deficits. Revenues are recognized based on the terms negotiated under these contracts.

We provide crude oil transportation services and refined petroleum products transportation and storage services to customers. Revenues are recorded when products are delivered and services have been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognize bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognize liquids terminal tank rental revenue ratably over the contract period. We recognize liquids terminal throughput revenue based on volumes received and volumes delivered. Liquids terminal minimum take-or-pay revenue is recognized at the end of the contract year or contract term depending on the terms of the contract. We recognize transmix processing revenues based on volumes processed or sold, and if applicable, when title has passed. We recognize energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of crude oil, natural gas liquids, carbon dioxide and natural gas production are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on our net interest. We record our entitled share of revenues based on entitled volumes and contracted sales prices. Since there is a ready market for oil and gas production, we sell the majority of our products soon after production at various locations, at which time title and risk of loss pass to the buyer. As a result, we maintain a minimum amount of product inventory in storage.

Environmental Matters

We expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense expenditures 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 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. For more information on our environmental disclosures, see Note 16.

Legal

We are subject to litigation and regulatory proceedings as the 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. When we identify specific litigation that is expected to continue for a significant period of time, is reasonably possible to occur, and may require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement, and we accrue for such amounts. 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. In general, we expense legal costs as incurred and all recorded legal liabilities are revised as better information becomes available. For more information on our legal disclosures, see Note 16.

Pensions and Other Postretirement Benefits

We fully recognize the overfunded or underfunded status of our consolidating subsidiaries' pension and postretirement benefit plans as either assets or liabilities on our balance sheet. A plan's funded status is the difference between the fair value of plan assets and the plan's benefit obligation. 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 income, until they are amortized to expense. For more information on our pension and postretirement benefit disclosures, see Note 9.

Noncontrolling Interests

Noncontrolling interests represents the outstanding ownership interests in our five operating limited partnerships and their consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income (or loss) 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 represents the ownership interests in our consolidated subsidiaries’ net assets held by parties other than us. It is presented separately as “Noncontrolling interests” within “Partners’ Capital.”

As of December 31, 2011, our noncontrolling interests consisted of the following: (i) the 1.0101% general partner interest in each of our five operating partnerships; (ii) the 0.5% special limited partner interest in SFPP, L.P.; (iii) the 50% interest in Globalplex Partners, a Louisiana joint venture owned 50% and controlled by Kinder Morgan Bulk Terminals, Inc.; (iv) the 33 1/3% interest in International Marine Terminals Partnership, a Louisiana partnership owned 66 2/3% and controlled by Kinder Morgan Operating L.P. “C”; (v) the approximate 31% interest in the Pecos Carbon Dioxide Company, a Texas general partnership owned approximately 69% and controlled by Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries; and (vi) the 35% interest in Guilford County Terminal Company, LLC, a limited liability company owned 65% and controlled by Kinder Morgan Southeast Terminals LLC.

Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statement of income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner’s tax attributes in us.

Some of our corporate subsidiaries and corporations in which we have an equity investment do pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized. For more information on our income tax disclosures, see Note 4.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which our reporting subsidiary operates, also referred to as its functional 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 income statements, 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 denominated or measured in a different local functional currency, for example the Canadian dollar for a Canadian subsidiary. We translate the assets and liabilities of each of our consolidating 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 partners’ capital equity accounts are translated by using historical exchange rates. Translation adjustments result from translating all assets and liabilities at current year-end rates, while partners’ capital equity is translated by using historical and weighted-average rates. The cumulative translation adjustments balance is reported as a component of “Accumulated other comprehensive income (loss)” within “Partners’ Capital” in our consolidated balance sheets.

Comprehensive Income

For each of the years ended December 31, 2011, 2010 and 2009, the difference between our net income and our comprehensive income resulted from (i) unrealized gains or losses on derivative contracts utilized for hedging our exposure to fluctuating expected future cash flows produced by both energy commodity price risk and interest rate risk; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other postretirement benefit plan liabilities. For more information on our risk management activities, see Note 13.

Cumulative revenues, expenses, gains and losses that under generally accepted accounting principals are included within our comprehensive income but excluded from our earnings are reported as “Accumulated other comprehensive income (loss)” within “Partners’ Capital” in our consolidated balance sheets. The following table summarizes changes in the amount of our “Accumulated other comprehensive income (loss)” in our accompanying consolidated balance sheets for each of the two years ended December 31, 2011 and 2010 (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjs.	Total Accumulated other comprehensive income/(loss)
December 31, 2009.....	\$ (418.9)	\$ 32.4	\$ (8.3)	\$ (394.8)
Change for period.....	111.2	99.5	(2.3)	208.4
December 31, 2010.....	(307.7)	131.9	(10.6)	(186.4)
Change for period.....	266.8	(44.0)	(33.1)	189.7
December 31, 2011.....	<u>\$ (40.9)</u>	<u>\$ 87.9</u>	<u>\$ (43.7)</u>	<u>\$ 3.3</u>

Limited Partners’ Net Income per Unit

We compute Limited Partners’ Net Income per Unit by dividing our limited partners’ interest in net income by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners’ Net Income per Unit are made in accordance with the “Earnings per Share” Topic of the Codification.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas, natural gas liquids 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 measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. If the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from fair value accounting and is accounted for using traditional accrual accounting.

Furthermore, changes in our derivative contracts’ fair values are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative contract meets those criteria, the contract’s gains and losses are allowed to offset related results on the hedged item in our income statement, and we are required to both formally designate the derivative contract as a hedge and document and assess the effectiveness of the contract associated with the transaction that receives hedge accounting. Only designated qualifying items that are effectively offset by changes in fair value or cash flows during the term of the hedge are eligible to use the special accounting for hedging.

Our derivative contracts that hedge our energy commodity price risks involve our normal business activities, which include the sale of natural gas, natural gas liquids and crude oil, and we have designated these derivative contracts as cash flow hedges—derivative contracts that hedge exposure to variable cash flows of forecasted transactions—and the effective portion of these derivative contracts’ gain or loss is initially reported as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is reported in earnings immediately. See Note 13 for more information on our risk management activities and disclosures.

Accounting for Regulatory Activities

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. The amount of regulatory assets and liabilities reflected within “Deferred charges and other assets” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheets as of December 31, 2011 and 2010 are not material to our consolidated balance sheets.

3. Acquisitions and Divestitures

Acquisitions

During 2011, 2010 and 2009, we completed the following acquisitions. For each of these acquisitions, we recorded all the acquired assets and assumed liabilities at their estimated fair market values as of the acquisition date. The results of operations from these acquisitions accounted for as business combinations are included in our consolidated financial statements from the acquisition date.

Ref.	Date	Acquisition	Assignment of Purchase Price (in millions)				
			Purchase Price	Current Assets	Property Plant & Equipment	Deferred Charges & Other	Goodwill
(1)	4/09	Megafleet Towing Co., Inc. Assets	\$ 21.7	\$ -	\$ 7.1	\$ 4.0	\$ 10.6
(2)	7/09	Portland Airport Pipeline	9.0	-	9.0	-	-
(3)	10/09	Crosstex Energy, L.P. Natural Gas Treating Business ...	270.7	15.0	181.7	25.4	48.6
(4)	11/09	Endeavor Gathering LLC	36.0	-	-	36.0	-
(5)	1/10	USD Terminal Acquisition	201.1	-	43.1	100.0	58.0
(6)	3/10	Mission Valley, California Products Terminal	13.5	-	13.5	-	-
(7)	3/10	Slay Industries Terminal Acquisition	101.6	-	67.9	32.8	0.9
(8)	5/10	KinderHawk Field Services LLC	917.4	-	-	917.4	-
(9)	7/10	Direct Fuels Terminal Acquisition	16.0	-	5.3	-	10.7
(10)	9/10	Gas-Chill, Inc. Natural Gas Treating Assets	13.1	-	8.0	5.1	-
(11)	10/10	Allied Concrete Terminal Acquisition	8.6	-	3.9	4.7	-
(12)	10/10	Chevron Refined Products Terminals	32.3	-	32.1	0.2	-
(13)	1/11	Watco Companies, LLC	50.0	-	-	50.0	-
(14)	2/11	Deeprock North, LLC	15.9	-	-	15.9	-
(15)	6/11	TGS Development, L.P. Terminal Acquisition	74.1	-	42.6	31.5	-
		KinderHawk Field Services LLC and EagleHawk Field					
(16)	7/11	Services LLC	912.1	35.5	641.6	140.8	94.2
(17)	11/11	SouthTex Treaters, Inc. Natural Gas Treating Assets	178.5	26.8	9.3	16.7	125.7
(18)	12/11	Lorton, Virginia Products Terminal	12.5	-	12.5	-	-
(19)	12/11	Watco Companies, LLC	50.0	-	-	50.0	-
(20)	12/11	Battleground Oil Specialty Terminal Company LLC	26.1	-	26.1	-	-

(1) Megafleet Towing Co., Inc. Assets

Effective April 23, 2009, we acquired certain terminals assets from Megafleet Towing Co., Inc. for an aggregate consideration of approximately \$21.7 million. Our consideration included \$18.0 million in cash and an obligation to pay additional cash consideration on April 23, 2014 (five years from the acquisition date) contingent upon the purchased assets providing us an agreed-upon amount of earnings, as defined by the purchase and sale agreement, during the five year period. The contingent consideration had a fair value of \$3.7 million as of the acquisition date. The acquired assets primarily consisted of nine marine vessels that provided towing and harbor boat services along the Gulf coast, the intracoastal waterway, and the Houston Ship Channel. The acquisition complemented and expanded our existing Gulf Coast and Texas petroleum coke terminal operations. We also recorded \$10.6 million of our purchase price as “Goodwill,” and we expected that approximately \$5.0 million of this goodwill amount would be deductible for tax purposes. We believed the primary item that generated the goodwill was the value of the synergies created between the acquired assets and our pre-existing Texas petroleum coke handling assets.

In February 2011, we sold certain assets acquired from Megafleet, and we contributed the ownership interest in the boat fleet business we acquired to a joint venture. For more information about these events, see “—Divestitures—Megafleet Towing Co., Inc. Assets” below.

(2) Portland Airport Pipeline

On July 31, 2009, we acquired a refined products pipeline, as well as associated valves, equipment and other fixtures, from Chevron Pipe Line Company for \$9.0 million in cash. The approximate 8.5 mile, 8-inch diameter pipeline is located in Multnomah County, Oregon. The line transports commercial jet fuel from our Willbridge liquids terminal facility to the Portland International Airport, both located in Portland, Oregon. It has an estimated system capacity of approximately 26,000 barrels per day. The acquisition enhanced our West Coast terminal operations, and the acquired assets are included in our Products Pipelines business segment.

(3) Crosstex Energy, L.P. Natural Gas Treating Business

On October 1, 2009, we acquired the natural gas treating business from Crosstex Energy, L.P. and Crosstex Energy, Inc. for an aggregate consideration of \$270.7 million, consisting of \$265.3 million in cash and assumed liabilities of \$5.4 million. The acquired assets primarily consisted of approximately 290 natural gas amine-treating and hydrocarbon dew-point control plants and related equipment, and are used to remove impurities and liquids from natural gas in order to meet pipeline quality specifications. The assets are predominantly located in Texas and Louisiana, with additional facilities located in Mississippi, Oklahoma, Arkansas and Kansas. The acquisition complemented and expanded the existing natural gas treating operations offered by our Texas intrastate natural gas pipeline group, and all of the acquired assets are included in our Natural Gas Pipelines business segment.

We measured the identifiable intangible assets acquired at fair value on the acquisition date, and accordingly, we recognized \$25.4 million in “Deferred charges and other assets,” representing the purchased fair value of separate and identifiable relationships with existing natural gas producing customers. We estimate the remaining useful life of these existing customer relationships to be between approximately eight and nine years. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, we recognized \$48.6 million of “Goodwill,” an intangible asset representing the future economic benefits expected to be derived from this acquisition that are not assigned to other identifiable, separately recognizable assets acquired. We believe the primary item that generated the goodwill is our ability to grow the business by leveraging our pre-existing natural gas operations (resulting from the increase in services now offered by our natural gas processing and treating operations in the state of Texas), and we believe that this value contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities—in the aggregate, these factors represented goodwill. Furthermore, this entire amount of goodwill is expected to be deductible for tax purposes.

(4) Endeavor Gathering LLC

On November 1, 2009, we acquired a 40% membership interest in Endeavor Gathering LLC for \$36.0 million in cash. Endeavor Gathering LLC owns the natural gas gathering and compression business previously owned by GMX Resources Inc. and its wholly-owned subsidiary, Endeavor Pipeline, Inc. Endeavor Gathering LLC provides natural gas gathering service to GMX Resources’ exploration and production activities in its Cotton Valley Sands and Haynesville/Bossier Shale horizontal well developments located in East Texas. The remaining 60% interest in Endeavor Gathering LLC is owned by GMX Resources, Inc., and Endeavor Pipeline Inc. remained operator of the business. The acquired investment complemented our existing natural gas gathering and transportation business located in the state of Texas. We account for this investment under the equity method of accounting, and the investment is included in our Natural Gas Pipelines business segment. For more information on our investments, see Note 6.

(5) USD Terminal Acquisition

On January 15, 2010, we acquired three ethanol handling train terminals from US Development Group LLC for an aggregate consideration of \$201.1 million, consisting of \$114.3 million in cash, \$81.7 million in common units, and \$5.1 million in assumed liabilities. The three train terminals are located in Linden, New Jersey; Baltimore, Maryland; and Euless, Texas. As part of the transaction, we announced the formation of a joint venture with US Development Group LLC to optimize and coordinate customer access to the three acquired terminals, other ethanol terminal assets we already own and operate, and other terminal projects currently under development by both parties. The acquisition complemented and expanded the ethanol and rail terminal operations we previously owned, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair values for all of the identifiable tangible and intangible assets acquired and liabilities assumed on the acquisition date, we assigned \$94.6 million of our combined purchase price to “Other intangibles, net,” and a combined \$5.4 million to “Other current assets” and “Deferred charges and other assets.” The acquired intangible amount represented the fair value of customer relationships, and we estimated the remaining useful

life of these customer relationships to be 10 years. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, we recognized \$58.0 million of “Goodwill,” an intangible asset representing the future economic benefits expected to be derived from this acquisition that are not assigned to other identifiable, separately recognizable assets. We believe the primary items that generated the goodwill are the value of the synergies created between the acquired assets and our pre-existing ethanol handling assets, and our expected ability to grow the business by leveraging our pre-existing experience in ethanol handling operations. We expect that the entire amount of goodwill will be deductible for tax purposes.

(6) Mission Valley Terminal Acquisition

On March 1, 2010, we acquired the refined products terminal assets at Mission Valley, California from Equilon Enterprises LLC (d/b/a Shell Oil Products US) for \$13.5 million in cash. The acquired assets included buildings, equipment, delivery facilities (including two truck loading racks), and storage tanks with a total capacity of approximately 170,000 barrels for gasoline, diesel fuel and jet fuel. The terminal operates under a long-term terminaling agreement with Tesoro Refining and Marketing Company. The acquisition enhanced our Pacific operations and complemented our existing West Coast terminal operations, and the acquired assets are included in our Products Pipelines business segment.

(7) Slay Industries Terminal Acquisition

On March 5, 2010, we acquired certain bulk and liquids terminal assets from Slay Industries for an aggregate consideration of \$101.6 million, consisting of \$97.0 million in cash, assumed liabilities of \$1.6 million, and an obligation to pay additional cash consideration of \$3.0 million in years 2013 through 2019, contingent upon the purchased assets providing us an agreed-upon amount of earnings during the three years following the acquisition. Including accrued interest, we expect to pay approximately \$2.0 million of this contingent consideration in the first half of 2013.

The acquired assets included (i) a marine terminal located in Sauget, Illinois; (ii) a transload liquid operation located in Muscatine, Iowa; (iii) a liquid bulk terminal located in St. Louis, Missouri; and (iv) a warehousing distribution center located in St. Louis. All of the acquired terminals have long-term contracts with large creditworthy shippers. As part of the transaction, we and Slay Industries entered into joint venture agreements at both the Kellogg Dock coal bulk terminal, located in Modoc, Illinois, and at the newly created North Cahokia terminal, located in Sauget and which has approximately 175 acres of land ready for development. All of the assets located in Sauget have access to the Mississippi River and are served by five rail carriers. The acquisition complemented and expanded our pre-existing Midwest terminal operations by adding a diverse mix of liquid and bulk capabilities, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair values for all of the identifiable tangible and intangible assets acquired and liabilities assumed, we assigned \$24.6 million of our combined purchase price to “Other intangibles, net” (representing customer contracts with an estimated remaining useful life of 20 years), and \$8.2 million to “Investments.” We also recorded \$0.9 million of our combined purchase price as “Goodwill,” representing certain advantageous factors that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets. In the aggregate, these factors represented goodwill, and we expect to deduct the entire amount of goodwill for tax purposes.

(8) KinderHawk Field Services LLC

On May 21, 2010, we purchased a 50% ownership interest in Petrohawk Energy Corporation’s natural gas gathering and treating business in the Haynesville shale gas formation located in northwest Louisiana for an aggregate consideration of \$917.4 million in cash. During a short transition period, Petrohawk continued to operate the business, and effective October 1, 2010, a newly formed company named KinderHawk Field Services LLC, owned 50% by us and 50% by Petrohawk, assumed the joint venture operations. The acquisition complemented and expanded our existing natural gas gathering and treating businesses, and we assigned our entire purchase price to “Investments” (including \$144.8 million of equity method goodwill, representing the excess of our investment cost over our proportionate share of the fair value of the joint venture’s identifiable net assets).

On July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC and a 25% equity ownership interest in Petrohawk’s natural gas gathering and treating business located in the Eagle Ford shale formation in South Texas. For more information about this acquisition, see “—(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC” below.

(9) Direct Fuels Terminal Acquisition

On July 22, 2010, we acquired a terminal with ethanol tanks, a truck rack and additional acreage in Dallas, Texas, from Direct Fuels Partners, L.P. for an aggregate consideration of \$16 million, consisting of \$15.9 million in cash and an assumed property tax liability of \$0.1 million. The acquired terminal facility is connected to and complements the Euless, Texas unit train terminal we acquired from USD Development Group LLC in January 2010 (described above in “—(5) USD Terminal Acquisition). All of the acquired assets are included in our Terminals business segment. After measuring all of the identifiable tangible and intangible assets acquired and liabilities assumed at fair value on the acquisition date, we recognized \$10.7 million of “Goodwill,” an intangible asset representing the future economic benefits expected to be derived from the acquisition that was not assigned to other identifiable, separately recognizable assets acquired. We believe the primary items that generated the goodwill are the value of the synergies created between the acquired assets and our pre-existing ethanol handling assets, and our expected ability to grow the business by leveraging our pre-existing experience in ethanol handling operations. We expect that the entire amount of goodwill will be deductible for tax purposes.

(10) Gas-Chill, Inc. Asset Acquisition

On September 1, 2010, we acquired the natural gas treating assets of Gas-Chill, Inc. for an aggregate consideration of \$13.1 million, consisting of \$10.5 million in cash paid on closing, and an obligation to pay a holdback amount of \$2.6 million within eighteen months from closing. We paid 50% of this holdback amount to Gas-Chill, Inc. in September 2011, and we expect to pay the remaining amount in the first quarter of 2012. The acquired assets primarily consisted of more than 100 mechanical refrigeration natural gas hydrocarbon dew point control units that are used to remove hydrocarbon liquids from natural gas streams prior to entering transmission pipelines. The acquisition complemented and expanded the existing natural gas treating operations offered by our Texas intrastate natural gas pipeline group, and all of the acquired assets are included in our Natural Gas Pipelines business segment. We assigned \$8.0 million of our purchase price to “Property, Plant and Equipment, net” and the remaining \$5.1 million to “Other intangibles, net” (representing both a technology-based asset and customer-related contract values).

(11) Allied Concrete Bulk Terminal Assets

On October 1, 2010, we acquired certain bulk terminal assets and real property located in Chesapeake, Virginia, from Allied Concrete Products, LLC and Southern Concrete Products, LLC for an aggregate consideration of \$8.6 million, consisting of \$8.1 million in cash and an assumed environmental liability of \$0.5 million. The acquired terminal facility is situated on 42 acres of land and can handle approximately 250,000 tons of material annually, including pumice, aggregates and sand. The acquisition complemented the bulk commodity handling operations at our nearby Elizabeth River terminal, also located in Chesapeake, and all of the acquired assets are included in our Terminals business segment. We assigned \$3.9 million of our purchase price to “Property, Plant and Equipment, net” and the remaining \$4.7 million to “Other intangibles, net” (representing customer-related contract values).

(12) Chevron Refined Products Terminal Assets

On October 8, 2010, we acquired four separate refined petroleum products terminals from Chevron U.S.A. Inc. for an aggregate consideration of \$32.3 million, consisting of \$31.5 million in cash and an assumed environmental liability of \$0.8 million. Combined, the terminals have storage capacity of approximately 650,000 barrels for gasoline, diesel fuel and jet fuel, and Chevron has entered into long-term contracts with us to terminal product at the terminals. The acquisition complemented and expanded our existing refined petroleum products assets, and all of the acquired assets are included in our Products Pipelines business segment. We assigned \$32.1 million of our purchase price to “Property, Plant and Equipment, net” and the remaining \$0.2 million to “Deferred charges and other assets” (representing the fair value of petroleum pipeline product additives).

(13) Watco Companies, LLC

On January 3, 2011, we purchased 50,000 Class A preferred shares of Watco Companies, LLC for \$50.0 million in cash in a private transaction. In connection with our purchase of these preferred shares, the most senior equity security of Watco, we entered into a limited liability company agreement with Watco that provides us certain priority and participating cash distribution and liquidation rights. Pursuant to the agreement, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and we participate partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco’s Board of Managers. As of December 31, 2010, we placed our \$50.0 million investment in a cash escrow account and we

reported this amount separately as “Restricted deposits” on our accompanying consolidated balance sheet. On December 28, 2011, we made an additional \$50 million investment in Watco, as described below in “—(19) Watco Companies, LLC.”

(14) Deeprock North, LLC

On February 17, 2011, Deeprock Energy Resources, LLC, Mecuria Energy Trading, Inc., and our subsidiary Kinder Morgan Cushing LLC, entered into formal agreements for a crude oil storage joint venture located in Cushing, Oklahoma. The joint venture is named Deeprock North, LLC, and on that date it operated an existing crude oil tank farm that had storage capacity of one million barrels. We contributed \$15.9 million for a 50% ownership interest in Deeprock North, and during 2011, we contributed an additional \$7.7 million for our proportionate share of costs related to the construction of three new storage tanks that provide for incremental storage capacity of 750,000 barrels. The new tanks were completed and placed in service during the fourth quarter of 2011. Deeprock Energy owns a 12.02% member interest in Deeprock North and is the construction manager and operator of the joint venture. Mecuria owns the remaining 37.98% member interest and is the anchor tenant for the joint venture’s crude oil capacity for the next five years with an option to extend. In addition, we entered into a development agreement with Deeprock Energy that gives us an option to participate in future expansions on Deeprock Energy’s remaining 254 acres of undeveloped land. We account for our investment under the equity method of accounting, and our investment and our pro rata share of Deeprock North’s operating results are included as part of our Terminals business segment.

(15) TGS Development, L.P. Terminal Acquisition

On June 10, 2011, we acquired a newly constructed petroleum coke terminal located in Port Arthur, Texas from TGS Development, L.P. (TGSD) for an aggregate consideration of \$74.1 million, consisting of \$42.9 million in cash, \$23.7 million in common units, and an obligation to pay additional consideration of \$7.5 million. We estimate our remaining \$7.5 million obligation will be paid to TGSD approximately one year from the closing (in May or June 2012), and will be settled in cash and/or common units, depending on TGSD’s election.

All of the acquired assets are located in Port Arthur, Texas, and include long-term contracts to provide petroleum coke handling and cutting services to improve the refining of heavy crude oil at Total Petrochemicals USA Inc.’s Port Arthur refinery. The refinery is expected to produce more than one million tons of petroleum coke annually. Based on our measurement of fair values for all of the identifiable tangible and intangible assets acquired, we assigned \$42.6 million of our combined purchase price to “Property, plant and equipment, net,” and the remaining \$31.5 million to “Other intangibles, net,” representing the combined fair values of two separate intangible customer contracts with Total. The acquisition complemented our existing Gulf Coast bulk terminal facilities and expanded our pre-existing petroleum coke handling operations. All of the acquired assets are included as part of our Terminals business segment.

(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC

Effective July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC that we did not already own and a 25% equity ownership interest in Petrohawk’s natural gas gathering and treating business located in the Eagle Ford shale formation in South Texas for an aggregate consideration of \$912.1 million, consisting of \$835.1 million in cash and assumed debt of \$77.0 million (representing 50% of KinderHawk’s borrowings under its bank credit facility as of July 1, 2011). We then repaid the outstanding \$154.0 million of borrowings and following this repayment, KinderHawk had no outstanding debt.

Following our acquisition of the remaining ownership interest on July 1, 2011, we changed our method of accounting from the equity method to full consolidation, and due to the fact that we acquired a controlling financial interest in KinderHawk, we remeasured our previous 50% equity investment in KinderHawk to its fair value. We recognized a \$167.2 million non-cash loss as a result of this remeasurement. The loss amount represents the excess of the carrying value of our investment (\$910.2 million as of July 1, 2011) over its fair value (\$743.0 million), and we reported this loss separately within the “Other Income (Expense)” section in our accompanying consolidated statements of income for the year ended December 31, 2011.

We then measured the fair values of the acquired identifiable tangible and intangible assets and the assumed liabilities on the acquisition date, and assigned the following amounts:

- \$35.5 million to current assets, primarily consisting of trade receivables and materials and supplies inventory;
- \$641.6 million to property, plant and equipment;

- \$93.4 million to our 25% investment in EagleHawk;
- \$883.2 million to a long-term intangible customer contract, representing the contract value of natural gas gathering services to be performed for Petrohawk over an approximate 20-year period; less
- \$92.8 million assigned to assumed liabilities, not including \$77.0 million for the 50% of KinderHawk's borrowings under its bank credit facility that we were previously responsible for.

Based on the excess of (i) the consideration we transferred (\$912.1 million) and the fair value of our previously held interest (\$743.0 million); over (ii) the combined fair value of net assets acquired (\$1,560.9 million), we recognized \$94.2 million of "Goodwill." This goodwill intangible asset represents the future economic benefits expected to be derived from this strategic acquisition that are not assignable to other individually identifiable, separately recognizable assets acquired. We believe the primary items that generated the goodwill are the value of the synergies created by expanding our natural gas gathering operations. We expect this entire amount of goodwill to be deductible for tax purposes. Furthermore, we believe the fair value of \$16.6 million assigned to "Accounts, notes and interest receivable, net" is fully realizable.

KinderHawk Field Services LLC owns and operates one of the largest natural gas gathering and midstream business in the Haynesville shale formation located in northwest Louisiana, consisting of more than 400 miles of pipeline with over 2.0 billion cubic feet per day of pipeline capacity. Currently, it gathers approximately 1.1 billion cubic feet of natural gas per day. The Eagle Ford natural gas gathering joint venture is named EagleHawk Field Services LLC, and we account for our 25% investment under the equity method of accounting. Petrohawk operates EagleHawk Field Services LLC and owns the remaining 75% ownership interest. The joint venture owns two midstream gathering systems in and around Petrohawk's Hawkville and Black Hawk areas of Eagle Ford and combined, the joint venture's assets as of December 31, 2011 consist of more than 280 miles of gas gathering pipelines and approximately 140 miles of condensate gathering lines. It also has a life of lease dedication of Petrohawk's Eagle Ford reserves that provides Petrohawk and other Eagle Ford producers with gas and condensate gathering, treating and condensate stabilization services.

All of the acquired assets are included in our Natural Gas Pipelines business segment. Additionally, on August 25, 2011, mining and oil company BHP Billiton completed its previously announced acquisition of Petrohawk Energy Corporation through a short-form merger under Delaware law. The merger was closed with Petrohawk being the surviving corporation as a wholly owned subsidiary of BHP Billiton. The acquisition will not affect the terms of our contracts with Petrohawk.

(17) SouthTex Treaters, Inc. Asset Acquisition

On November 30, 2011, we acquired a manufacturing complex and certain natural gas treating assets from SouthTex Treaters, Inc. for an aggregate consideration of \$178.5 million, consisting of \$151.5 million in cash and assumed liabilities of \$27.0 million. SouthTex Treaters, Inc. is a leading manufacturer, designer and fabricator of natural gas treating plants that are used to remove impurities (carbon dioxide and hydrogen sulfide) from natural gas before it is delivered into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. The acquisition complemented and expanded our existing natural gas treating business, and all of the acquired operations are included in our Natural Gas Pipelines business segment.

Based on our measurement of fair values for all of the identifiable tangible and intangible assets acquired and liabilities assumed, we assigned \$26.8 million of our combined purchase price to current assets (consisting of \$13.5 million included within "Accounts, notes and interest receivable, net" and \$13.3 million included within "Inventories"), \$9.3 million to "Property, plant and equipment, net," \$16.6 million to "Deferred charges and other assets" (representing the fair value of construction in process costs), and \$0.1 million to a non-compete agreement included within "Other intangibles, net." The remaining \$125.7 million of our purchase price was recorded to "Goodwill," an intangible asset representing the future economic benefits expected to be derived from this acquisition that are not assigned to other identifiable, separately recognizable assets acquired. We believe the fair value of receivables is fully realizable, and we believe the primary item that generated the goodwill is our ability to grow the business by leveraging our pre-existing natural gas treating operations, and we believe that this growth potential contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities. Furthermore, this entire amount of goodwill is expected to be deductible for tax purposes.

(18) Lorton, Virginia Products Terminal

On December 15, 2011, we acquired a refined petroleum products terminal located on a 14-acre site in Lorton, Virginia from Motiva Enterprises, LLC for an aggregate consideration of \$12.5 million in cash. The terminal is served exclusively by the Plantation Pipeline and has storage capacity of approximately 450,000 barrels for refined petroleum products like gasoline and jet fuel. The acquisition complemented and expanded our existing refined petroleum products assets in the northern Virginia market, and the acquired terminal is included as part of our Products Pipelines business segment. We assigned the entire purchase price amount to “Property, Plant and Equipment, net.”

(19) Watco Companies, LLC

On December 28, 2011, we purchased an additional 50,000 Class A preferred shares of Watco Companies, LLC for \$50.0 million in cash in a private transaction. The priority and participating cash distribution and liquidation rights associated with these shares are similar to the rights associated with the 50,000 Class A preferred shares we acquired on January 3, 2011—we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter (13% annually), and we participate partially in additional profit distributions at a rate equal to 0.5%.

Watco Companies, LLC is the largest privately held short line railroad company in the United States, operating 22 short line railroads on approximately 3,500 miles of leased and owned track. Our investment provided capital to Watco for further expansion of specific projects and complemented our existing terminal network. It also provides our customers more transportation services for many of the commodities that we currently handle, and offers us the opportunity to share in additional growth opportunities through new projects. As of December 31, 2011, our net equity investment in Watco totaled \$101.7 million and is included within “Investments” on our accompanying consolidated balance sheet. We account for our investment under the equity method of accounting, and we include it in our Terminals business segment.

(20) Battleground Oil Specialty Terminal Company LLC

On November 8, 2011 we announced our initial 50% equity participation in BOSTCO, and we paid a combined \$12.0 million to acquire a 50% Class A member interest (consisting of \$11.6 million paid in October 2011 and \$0.4 million of pre-development costs incurred and paid for during 2010). We also made cash contributions of \$6.0 million to BOSTCO in December 2011. Effective December 29, 2011, we acquired from TransMontaigne Partners, L.P. the remaining 50% Class A member interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO) that we did not already own for an aggregate consideration of \$8.1 million in cash (net of an acquired cash balance of \$9.9 million). TransMontaigne also received a transferrable option to buy 50% of our ownership interest at any time prior to January 20, 2013; however, we are currently unable to predict whether it will exercise this purchase option. Following our acquisition of the remaining ownership interest on December 29, 2011, we changed our method of accounting from the equity method to full consolidation, and based on our measurement of fair values for all of the identifiable tangible assets acquired, we assigned \$26.1 million to property, plant and equipment.

BOSTCO will construct, own and operate an approximately \$430 million oil terminal located on the Houston Ship Channel. Phase I of the project includes the design and construction of 52 tanks with combined storage capacity of approximately 6.6 million barrels for handling residual fuel, feedstocks, distillates and other black oils. BOSTCO will initially be a water-in, water-out facility with the capability of handling ships with large drafts up to 45 feet, and we have executed terminal service contracts or letters of intent with customers for almost all of the Phase I storage capacity. The acquisition of BOSTCO complemented and expanded our existing Gulf Liquids terminal operations, and all of the acquired assets (including the acquired cash balance) are included in our Terminals business segment.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2010 as if they had occurred as of January 1, 2010 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Divestitures

Cypress Interstate Pipeline LLC

Effective October 1, 2010, Westlake Petrochemicals LLC, a wholly-owned subsidiary of Westlake Chemical Corporation, exercised an option it held to purchase a 50% ownership interest in our Cypress Pipeline. Accordingly, we

sold a 50% interest in our subsidiary, Cypress Interstate Pipeline LLC, to Westlake and we received proceeds of \$10.2 million. At the time of the sale, the carrying value of the net assets of Cypress Interstate Pipeline LLC totaled \$20.0 million and consisted mostly of property, plant and equipment. In the fourth quarter of 2010, we recognized an \$8.8 million gain from this sale, including an \$8.6 million gain amount related to the remeasurement of our retained investment to its fair value. Due to the loss of control of Cypress Interstate Pipeline LLC, we recognized the retained investment at its fair value, and the gain amount related to remeasurement represents the excess of the fair value of our retained investment (\$18.6 million as of October 1, 2010) over its carrying value (\$10.0 million). This fair value of our retained investment was determined by applying a multiple to the future annual cash flows expected from our retained 50% interest. The \$10.2 million value of the transaction with Westlake Chemical Corporation was based on a contract price and does not represent the fair value of a 50% interest in the Cypress Pipeline in an orderly transaction between market participants. We now account for our retained investment under the equity method of accounting. We included the entire gain within the caption “Other, net” in our accompanying consolidated statement of income for the year ended December 31, 2010.

Megafleet Towing Co., Inc. Assets

On February 9, 2011, we sold a marine vessel to Kirby Inland Marine, L.P., and additionally, we and Kirby formed a joint venture named Greens Bayou Fleeting, LLC. Pursuant to the joint venture agreement, we sold our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009 (discussed above in “—Acquisitions—(1) Megafleet Towing Co., Inc. Assets”) to the joint venture for \$4.1 million in cash and a 49% ownership interest in the joint venture. Kirby then made cash contributions to the joint venture in exchange for the remaining 51% ownership interest. Related to the above transactions, we recorded a loss of \$5.5 million (\$4.1 million after tax) in the fourth quarter of 2010 to write down the carrying value of the net assets to be sold to their estimated fair values as of December 31, 2010. We included this loss within the caption “Other expense (income),” and we recorded the \$1.4 million decrease in income tax expense within the caption “Income Tax (Expense) Benefit” in our accompanying consolidated statement of income for the year ended December 31, 2010.

In the first quarter of 2011, after final reconciliation and measurement of all of the net assets sold, we recognized a combined \$2.2 million increase in income from the sale of these net assets, primarily consisting of a \$1.9 million reduction in income tax expense, which is included within the caption “Income Tax (Expense) Benefit” in our accompanying consolidated statement of income for the year ended December 31, 2011. Additionally, the sale of our ownership interest resulted in a \$10.6 million non-cash reduction in our goodwill (see Note 7), and was a transaction with a related party (see Note 11).

River Consulting, LLC and Devco USA, L.L.C.

Effective April 1, 2011, we sold 51% ownership interests in two separate wholly-owned subsidiaries to two separate buyers, for an aggregate consideration of \$8.1 million, consisting of a \$4.1 million note receivable, \$1.0 million in cash, and a \$3.0 million receivable for the settlement of working capital items. Following the sale, we continue to own 49% membership interests in both River Consulting, LLC, a company engaged in the business of providing engineering, consulting and management services, and Devco USA, L.L.C., a company engaged in the business of processing, handling and marketing sulfur, and selling related pouring equipment. At the time of the sale, the combined carrying value of the net assets (and members’ capital on a 100% basis) of both entities totaled approximately \$8.8 million and consisted mostly of technology-based assets and trade receivables. We now account for our retained investments under the equity method of accounting.

We recognized a \$3.6 million pre-tax gain from the sale of these ownership interests (including a \$2.1 million gain related to the remeasurement of our retained investment to fair value) and we included this gain within the caption “Other, net” in our accompanying consolidated statements of income for the year ended December 31, 2011. We also recognized a \$1.4 million increase in income tax expense related to this gain, which is included within the caption “Income Tax (Expense) Benefit” in our accompanying consolidated statement of income for the year ended December 31, 2011.

Arrow Terminals B.V.

Effective August 31, 2011, we sold the outstanding share capital of our wholly-owned subsidiary Arrow Terminals B.V. to Pacorini Metals Europe B.V. for an aggregate consideration of \$13.3 million in cash. Arrow Terminals B.V. owns and operates a bulk terminal facility located in the seaport area of Vlissingen, Netherlands. The terminal is primarily engaged in the business of storing, handling and distributing bulk ferro alloys and general commodities. Including the removal of our cumulative translation adjustments balance and our estimated costs to sell, we recognized a

\$1.3 million pre-tax gain from the sale of Arrow Terminals B.V. and we included this gain within the caption “Other expense (income)” in our accompanying consolidated statements of income for the year ended December 31, 2011.

4. Income Taxes

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

	Year Ended December 31,		
	2011	2010	2009
United States	\$ 1,234.9	\$ 1,288.7	\$ 1,263.4
Foreign	79.3	73.0	76.1
Total consolidated Income Before Income Taxes	<u>\$ 1,314.2</u>	<u>\$ 1,361.7</u>	<u>\$ 1,339.5</u>

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

	Year Ended December 31,		
	2011	2010	2009
Taxes current expense:			
Federal	\$ 13.3	\$ 4.8	\$ 2.7
State	15.9	11.1	15.1
Foreign	3.4	3.6	(1.0)
Total	<u>32.6</u>	<u>19.5</u>	<u>16.8</u>
Taxes deferred expense:			
Federal	(6.4)	4.7	7.3
State	(1.1)	(0.2)	1.0
Foreign	20.7	10.6	30.6
Total	<u>13.2</u>	<u>15.1</u>	<u>38.9</u>
Total tax provision	<u>\$ 45.8</u>	<u>\$ 34.6</u>	<u>\$ 55.7</u>
Effective tax rate	3.5%	2.5%	4.2%

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

	Year Ended December 31,		
	2011	2010	2009
Federal income tax rate	35.0 %	35.0 %	35.0 %
Increase (decrease) as a result of:			
Partnership earnings not subject to tax	(35.0) %	(35.0) %	(35.0) %
Corporate subsidiary earnings subject to tax	(0.7) %	- %	- %
Income tax expense attributable to corporate equity earnings	1.3 %	0.7 %	0.8 %
Income tax expense attributable to foreign corporate earnings	1.8 %	1.0 %	2.2 %
State taxes	1.1 %	0.8 %	1.2 %
Effective tax rate	<u>3.5 %</u>	<u>2.5 %</u>	<u>4.2 %</u>

Our deferred tax assets and liabilities as of December 31, 2011 and 2010 resulted from the following (in millions):

	December 31,	
	2011	2010
Deferred tax assets:		
Book accruals	\$ 0.3	\$ 2.1
Net Operating Loss/Tax credits	30.5	17.8
Other	3.0	1.3
Total deferred tax assets	<u>33.8</u>	<u>21.2</u>
Deferred tax liabilities:		
Property, plant and equipment	277.4	263.9
Other	6.0	5.6
Total deferred tax liabilities	<u>283.4</u>	<u>269.5</u>
Net deferred tax liabilities	<u>\$ 249.6</u>	<u>\$ 248.3</u>

We account for uncertainty in income taxes in accordance with the “Income Taxes” Topic of the Codification. Pursuant to these provisions, we must 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 on the past administrative practices and precedents of the taxing authority. The tax benefits recognized in our 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 beginning and ending gross unrecognized tax benefits (excluding interest and penalties) for each of the years ended December 31, 2011 and 2010 is as follows (in millions):

	Year Ended December 31,	
	2011	2010
Balance at beginning of period	\$ 33.4	\$ 23.3
Additions based on current year tax positions	7.8	10.2
Additions based on prior year tax positions	-	-
Reductions based on settlements with taxing authority	-	-
Reductions due to lapse in statute of limitations	-	(0.1)
Balance at end of period	<u>\$ 41.2</u>	<u>\$ 33.4</u>

Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense. During the year ended December 31, 2011, we recognized approximately \$0.9 million in interest expense; during the year ended December 31, 2010, we recognized reductions in interest expense of approximately \$0.5 million; and during the year ended December 31, 2009, we recognized approximately \$1.1 million in interest expense.

As of December 31, 2011, (i) we had \$2.7 million of accrued interest and no accrued penalties; (ii) we believe it is reasonably possible that our \$41.2 million liability for unrecognized tax benefits will increase by approximately \$7.6 million during the next twelve months; and (iii) we believe the full amount of \$41.2 million of unrecognized tax benefits, if recognized, would favorably affect our effective income tax rate in future periods. As of December 31, 2010, we had \$1.8 million of accrued interest and no accrued penalties. In addition, we have U.S. and state tax years open to examination for the periods 2006 through 2011.

5. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2011 and 2010, our property, plant and equipment consisted of the following (in millions):

	December 31,	
	2011	2010
Natural gas, liquids, crude oil and carbon dioxide pipelines	\$ 7,759.4	\$ 7,071.1
Natural gas, liquids, carbon dioxide, and terminals station equipment.....	9,569.0	8,976.2
Natural gas, liquids (including linefill), and transmix processing	226.3	233.7
Other	1,453.5	1,322.7
Accumulated depreciation, depletion, and amortization.....	<u>(4,979.7)</u>	<u>(4,150.6)</u>
	14,028.5	13,453.1
Land and land right-of-way	769.5	638.5
Construction work in process	797.8	512.3
Property, plant and equipment, net.....	<u>\$ 15,595.8</u>	<u>\$ 14,603.9</u>

Depreciation, depletion, and amortization expense charged against property, plant and equipment was \$886.1 million in 2011, \$852.8 million in 2010 and \$829.6 million in 2009.

Asset Retirement Obligations

As of December 31, 2011 and 2010, we recognized asset retirement obligations in the aggregate amount of \$125.2 million and \$122.0 million, respectively. 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 our surface wellhead equipment and compressors. We included \$10.8 million and \$2.5 million, respectively, of our total asset retirement obligations as of December 31, 2011 and 2010 within “Accrued other current liabilities” in our accompanying consolidated balance sheets. The remaining amounts are included within “Other long-term liabilities and deferred credits” at each reporting date.

A reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations for each of the years ended December 31, 2011 and 2010 is as follows (in millions):

	Year Ended December 31,	
	2011	2010
Balance at beginning of period	\$ 122.0	\$ 100.9
Liabilities incurred/revised.....	12.1	23.7
Liabilities settled.....	(16.3)	(9.1)
Accretion expense	7.4	6.5
Balance at end of period	<u>\$ 125.2</u>	<u>\$ 122.0</u>

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.

6. Investments

We reported a combined \$3,346.2 million as “Investments” in our accompanying consolidated balance sheet as of December 31, 2011. As of December 31, 2010, our investments totaled \$3,886.0 million. Our investments primarily consist of equity investments where we hold significant influence over investee actions and which we account for under the equity method of accounting.

As of December 31, 2011 and 2010, our investments consisted of the following (in millions):

	December 31,	
	2011	2010
Rockies Express Pipeline LLC	\$ 1,594.8	\$ 1,703.0
Midcontinent Express Pipeline LLC.....	666.6	706.4
Plantation Pipe Line Company	185.0	190.3
Fayetteville Express Pipeline LLC	173.3	0.2
Red Cedar Gathering Company.....	167.8	163.2
EagleHawk Field Services LLC	141.0	-
Eagle Ford Gathering LLC	117.5	29.9
Watco Companies, LLC	101.7	-
Express pipeline system.....	65.0	68.5
Cortez Pipeline Company	10.4	9.9
KinderHawk Field Services LLC	-	924.6
All others	114.9	81.8
Total equity investments.....	<u>3,338.0</u>	<u>3,877.8</u>
Bond investments	<u>8.2</u>	<u>8.2</u>
Total investments.....	<u>\$ 3,346.2</u>	<u>\$ 3,886.0</u>

The decrease in the carrying amount of our equity investments since December 31, 2010 was primarily due to our July 1, 2011 acquisition of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own. On that date, we exchanged our status as an owner of an equity investment in KinderHawk for a full controlling financial interest, and we began accounting for our investment under the full consolidation method. For further information pertaining to our KinderHawk acquisitions, see Note 3 “Acquisitions and Divestitures—Acquisitions—(8) KinderHawk Field Services LLC” and “—(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC.”

As shown in the table above, our significant equity investments as of December 31, 2011 consisted of the following:

- Rockies Express Pipeline LLC—we operate and own a 50% ownership interest in Rockies Express Pipeline LLC, the sole owner of the Rockies Express natural gas pipeline system. The remaining ownership interests in Rockies Express Pipeline LLC are owned by subsidiaries of Semptra Energy (25%) and ConocoPhillips (25%);
- Midcontinent Express Pipeline LLC—we operate and own a 50% ownership interest in Midcontinent Express Pipeline LLC. It is the sole owner of the Midcontinent Express natural gas pipeline system. The remaining ownership interest in Midcontinent Express Pipeline LLC is owned by subsidiaries of Regency Energy Partners, L.P. (50%);

- Plantation Pipe Line Company—we operate and own a 51.17% ownership interest in Plantation Pipe Line Company, 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 participating rights; therefore, we do not control Plantation Pipe Line Company, and we account for our investment under the equity method;
- Fayetteville Express Pipeline LLC—we own a 50% ownership interest in Fayetteville Express Pipeline LLC, 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 Fayetteville Express Pipeline LLC. The Fayetteville Express system began interim transportation service on October 12, 2010, and began full operations on January 1, 2011; however, as of December 31, 2010, we had no material net investment in Fayetteville Express Pipeline LLC because in November 2009, Fayetteville Express Pipeline LLC established and made borrowings under its own revolving bank credit facility in order to fund its pipeline development and construction costs and to make distributions to its member owners to reimburse them for prior contributions;
- Red Cedar Gathering Company—we own a 49% ownership interest in the Red Cedar Gathering Company. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar is the sole owner of the Red Cedar natural gas gathering, compression and treating system;
- EagleHawk Field Services LLC—we acquired a 25% ownership interest in the EagleHawk Field Services LLC from Petrohawk Energy Corporation effective July 1, 2011. For further information about this acquisition, see Note 3 “Acquisitions and Divestitures—Acquisitions—(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC;”
- Eagle Ford Gathering LLC—on May 14, 2010, we and Copano Energy, L.L.C. entered into formal agreements for a joint venture to provide natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford Shale formation in south Texas. We named the joint venture Eagle Ford Gathering LLC, and we own a 50% member interest in Eagle Ford Gathering LLC. Copano owns the remaining 50% interest and serves as operator and managing member of Eagle Ford Gathering LLC;
- Watco Companies, LLC—we made a combined \$100.0 million preferred equity investment in Watco Companies, LLC, the largest privately held short line railroad company in the United States. We acquired 100,000 Class A preferred shares and pursuant to the terms of our investment, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and we participate partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco’s Board of Managers;
- Express pipeline system—we acquired a 33 1/3% ownership interest in the Express pipeline system from KMI effective August 28, 2008; and
- Cortez Pipeline Company—we operate and own a 50% ownership interest in the Cortez Pipeline Company, the sole owner of the Cortez carbon dioxide pipeline system. A subsidiary of Exxon Mobil Corporation owns a 37% ownership interest and Cortez Vickers Pipeline Company owns the remaining 13% ownership interest.

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

	Year Ended December 31,		
	2011	2010	2009
Rockies Express Pipeline LLC.....	\$ 86.7	\$ 87.6	\$ 98.5
Plantation Pipe Line Company.....	44.7	30.3	26.8
Midcontinent Express Pipeline LLC	42.7	30.1	14.7
Red Cedar Gathering Company	31.9	28.7	24.9
Cortez Pipeline Company.....	24.1	22.5	22.3
Fayetteville Express Pipeline LLC.....	23.8	-	3.6
KinderHawk Field Services LLC	22.1	19.5	-
Eagle Ford Gathering LLC.....	11.2	(0.1)	-
Watco Companies, LLC.....	6.6	-	-
EagleHawk Field Services LLC	3.5	-	-
Express pipeline system	(2.0)	(3.3)	(4.1)
All others.....	15.8	7.8	3.0
Total	<u>\$ 311.1</u>	<u>\$ 223.1</u>	<u>\$ 189.7</u>
Amortization of excess costs.....	<u>\$ (6.7)</u>	<u>\$ (5.8)</u>	<u>\$ (5.8)</u>

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

Income Statement	Year Ended December 31,		
	2011	2010	2009
Revenues	\$ 2,312.9	\$ 1,645.7	\$ 1,215.6
Costs and expenses.....	1,747.3	1,204.0	824.5
Earnings before extraordinary items and cumulative effect of a change in accounting principle	565.6	441.7	391.1
Net income	<u>\$ 565.6</u>	<u>\$ 441.7</u>	<u>\$ 391.1</u>

Balance Sheet	December 31,	
	2011	2010
Current assets.....	\$ 491.5	\$ 486.6
Non-current assets	\$ 11,488.6	\$ 12,712.1
Current liabilities	\$ 545.8	\$ 622.3
Non-current liabilities	\$ 5,311.9	\$ 5,451.6
Partners'/Owners' equity	\$ 6,122.4	\$ 7,124.8

For information on regulatory matters affecting certain of our equity investments, see Note 17.

As of December 31, 2011 and 2010, our investment amounts also included a bond investment totaling \$8.2 million. This investment consisted of certain tax exempt, fixed-income development revenue bonds we acquired in the fourth quarter of 2008. Because we have both the ability and the intent to hold these debt securities to maturity, we account for this investment at historical cost. We acquired our bond investment by issuing notes under the Gulf Opportunity Zone Act of 2005, which is further discussed in Note 8 "Debt—Subsidiary Debt—Gulf Opportunity Zone Bonds."

7. Goodwill and Other Intangibles

Goodwill and Excess Investment Cost

We record the excess of the cost of an acquisition price over the fair value of acquired net assets as an asset on our balance sheet. This amount is referred to and reported separately as "Goodwill" in our accompanying consolidated balance sheets. 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, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes, but combined with Products Pipelines for presentation in the table below); (iii) Natural Gas Pipelines; (iv) CO₂; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2011 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 8.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for each of the two years ended December 31, 2011 and 2010 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO₂	Terminals	Kinder Morgan Canada	Total
Historical Goodwill.....	\$ 263.2	\$ 337.0	\$ 46.1	\$ 266.9	\$ 613.1	\$ 1,526.3
Accumulated impairment losses(a)....	-	-	-	-	(377.1)	(377.1)
Balance as of December 31, 2009.....	263.2	337.0	46.1	266.9	236.0	1,149.2
Acquisitions(b).....	-	-	-	71.0	-	71.0
Currency translation adjustments.....	-	-	-	-	13.4	13.4
Balance as of December 31, 2010.....	263.2	337.0	46.1	337.9	249.4	1,233.6
Acquisitions(c).....	-	219.9	-	-	-	219.9
Disposals(d).....	-	-	-	(11.8)	-	(11.8)
Currency translation adjustments.....	-	-	-	-	(5.5)	(5.5)
Balance as of December 31, 2011.....	<u>\$ 263.2</u>	<u>\$ 556.9</u>	<u>\$ 46.1</u>	<u>\$ 326.1</u>	<u>\$ 243.9</u>	<u>\$ 1,436.2</u>

- (a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of U.S. generally accepted accounting principles, the consideration of this transaction caused KMI to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, KMI recorded a goodwill impairment charge of \$377.1 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment is now included in our accumulated impairment losses. We have no other goodwill impairment losses.
- (b) 2010 acquisition amount relates primarily to our January 2010 purchase of three ethanol handling train terminals from US Development Group LLC (discussed further in Note 3).
- (c) 2011 acquisition amount consists of (i) \$125.7 million relating to our acquisition of natural gas treating assets from SouthTex Treaters, Inc. and (ii) \$94.2 million relating to our purchase of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own (both discussed further in Note 3).
- (d) 2011 disposal amount consists of (i) \$10.6 million related to the sale of our ownership interest in the boat fleet business we acquired from Megafleet Towing Co., Inc. in April 2009; and (ii) \$1.2 million related to the sale of our subsidiary Arrow Terminals B.V. (both discussed further in Note 3).

For more information on our accounting for goodwill, see Note 2 “Summary of Significant Accounting Policies—Goodwill.”

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 consolidating 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 \$193.1 million and \$166.0 million as of December 31, 2011 and 2010, respectively. The increase since December 31, 2010 was mainly due to our July 1, 2011 acquisition of a 25% ownership interest in EagleHawk Field Services LLC (discussed further in Note 3).

In almost all instances, this differential, relating to the discrepancy between our share of the investee's recognized net assets at book values and at current fair values, represents our share of undervalued depreciable assets, and since those assets (other than land) are subject to depreciation, we amortize this portion of our investment cost against our share of investee earnings. As of December 31, 2011, this excess investment cost is being amortized over a weighted average life of approximately 22.1 years.

The second differential, representing total unamortized excess cost over underlying fair value of net assets acquired (equity method goodwill) totaled \$138.2 million and \$283.0 million as of December 31, 2011 and 2010, respectively. The decrease in our equity method goodwill since December 31, 2010 was due to our July 1, 2011 acquisition of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own (discussed further in Note 3). Following our acquisition of the remaining 50% interest in KinderHawk, we changed our method of accounting from the equity method to the full consolidation method.

This differential is not subject to amortization but rather to impairment testing. Accordingly, in addition to our annual impairment test of goodwill, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method, as well as the amortization period for such assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives. Our impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. As of December 31, 2011, we believed no such impairment had occurred and no reduction in estimated useful lives was warranted.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. These intangible assets have definite lives and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets.

Following is information, as of December 31, 2011 and 2010, related to our intangible assets subject to amortization (in millions):

	December 31,	
	2011	2010
Customer contracts, relationships and agreements		
Gross carrying amount	\$ 1,317.9	\$ 399.8
Accumulated amortization.....	(172.6)	(112.0)
Net carrying amount.....	<u>1,145.3</u>	<u>287.8</u>
Lease value, technology-based assets and other		
Gross carrying amount	10.6	17.9
Accumulated amortization.....	(3.9)	(3.5)
Net carrying amount.....	<u>6.7</u>	<u>14.4</u>
Total Other intangibles, net.....	<u>\$ 1,152.0</u>	<u>\$ 302.2</u>

Our customer contracts, relationships and agreements relate primarily to our Natural Gas Pipelines and Terminals business segments. These intangible assets include contracts and relationships for gathering natural gas, and for handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, coal, petroleum coke, fertilizer, steel and ores. The values of these intangible assets were determined by us 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. The increase in the carrying amount of our customer contracts, relationships and agreements since December 31, 2010 was mainly due to the acquisition of (i) a natural gas gathering customer contract in July 2011, associated with our purchase of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own; and (ii) two separate petroleum coke handling customer contracts in June 2011, associated with our purchase of terminal assets from TGS Development, L.P. Both acquisitions are described further in Note 3.

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 each of the years ended December 31, 2011, 2010 and 2009, the amortization expense on our intangibles totaled \$61.0 million, \$45.5 million and \$16.5 million, respectively. These expense amounts primarily consisted of amortization of our customer contracts, relationships and agreements. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2012 – 2016) is approximately \$78.8 million, \$74.9 million, \$71.7 million, \$67.6 million and \$63.8 million, respectively. As of December 31, 2011, the weighted average amortization period for our intangible assets was approximately 18.4 years.

8. 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 consolidated statements of income.

The net carrying amount of our debt (including both short-term and long-term amounts and excluding the value of interest rate swap agreements) as of December 31, 2011 and 2010 was \$12,797.3 million and \$11,539.8 million, respectively. The weighted average interest rate on all of our borrowings was approximately 4.26% during 2011 and 4.35% during 2010.

Short-Term Debt

Our outstanding short-term debt as of December 31, 2011 was \$1,637.8 million. The balance consisted of (i) \$450.0 million in principal amount of 7.125% senior notes due March 15, 2012; (ii) \$500.0 million in principal amount of 5.85% senior notes due September 15, 2012; (iii) \$644.8 million of commercial paper borrowings; (iv) \$23.7 million in principal amount of tax-exempt bonds that mature on April 1, 2024, that are due on demand pursuant to certain standby purchase agreement provisions contained in the bond indenture (our subsidiary Kinder Morgan Operating L.P. “B” is the obligor on the bonds); (v) the \$9.9 million remaining outstanding balance of a 5.40% long-term note payable (our subsidiaries Kinder Morgan Operating L.P. “A” and Kinder Morgan Canada Company are the obligors on the note); (vi) a \$7.6 million portion of 5.23% long-term senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); (vii) a \$1.1 million 7.17% note payable (our subsidiary Globalplex Partners, a Louisiana joint venture owned 50% and controlled by Kinder Morgan Bulk Terminals, Inc. is the obligor on the note, and we expect the joint venture will terminate during 2012); and (viii) a \$0.7 million portion of 6.00% long-term note payable (our subsidiary Kinder Morgan Arrow Terminals, L.P. is the obligor on the note).

Our outstanding short-term debt as of December 31, 2010 was \$1,262.4 million. The balance consisted of (i) \$700.0 million in principal amount of 6.75% senior notes that matured on March 15, 2011; (ii) \$522.1 million of commercial paper borrowings; (iii) \$23.7 million in principal amount of tax-exempt bonds due on demand from our subsidiary Kinder Morgan Operating L.P. “B”; (iv) a \$9.4 million portion of the 5.40% long-term note payable due from our subsidiaries Kinder Morgan Operating L.P. “A” and Kinder Morgan Canada Company; and (v) a \$7.2 million portion of the 5.23% long-term senior notes due from our subsidiary Kinder Morgan Texas Pipeline, L.P.

Credit Facility

On July 1, 2011, we amended our \$2.0 billion three-year, senior unsecured revolving credit facility to, among other things, (i) allow for borrowings of up to \$2.2 billion; (ii) extend the maturity of the credit facility from June 23, 2013 to July 1, 2016; (iii) permit an amendment to allow for borrowings of up to \$2.5 billion; and (iv) decrease the interest rates and commitment fees for borrowings under this facility. The credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit facility can be used for general partnership purposes and as a backup for our commercial paper program. There were no borrowings under the credit facility as of December 31, 2011 or as of December 31, 2010.

Additionally, as of December 31, 2011, the amount available for borrowing under our credit facility was reduced by a combined amount of \$875.1 million, consisting of \$644.8 million of commercial paper borrowings and \$230.3 million of letters of credit, consisting of: (i) a \$100.0 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined \$86.3 million in three letters of credit that support tax-exempt bonds; (iii) a \$16.2 million letter of credit that supports debt securities issued by the Express pipeline system; (iv) a \$10.7 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined \$17.1 million in other letters of credit supporting other obligations of us and our subsidiaries.

Interest on the credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt. Additionally, our \$2.2 billion credit facility included the following restrictive covenants as of December 31, 2011:

- total debt divided by earnings before interest, income taxes, depreciation and amortization for the preceding four quarters may not exceed:
- 5.5, in the case of any such period ended on the last day of (i) a fiscal quarter in which we make any Specified Acquisition (as defined in the credit facility), or (ii) the first or second fiscal quarter next succeeding such a fiscal quarter; or
- 5.0, in the case of any such period ended on the last day of any other fiscal quarter;
- certain limitations on entering into mergers, consolidations and sales of assets;
- limitations on granting liens; and
- prohibitions on making any distribution to holders of units if an event of default exists or would exist upon making such distribution.

In addition to normal repayment covenants, under the terms of our credit facility, the occurrence at any time of any of the following would constitute an event of default (i) our failure to make required payments of any item of indebtedness or any payment in respect of any hedging agreement, provided that the aggregate outstanding principal amount for all such indebtedness or payment obligations in respect of all hedging agreements is equal to or exceeds \$75 million; (ii) our general partner's failure to make required payments of any item of indebtedness, provided that the aggregate outstanding principal amount for all such indebtedness is equal to or exceeds \$75 million; (iii) adverse judgments rendered against us for the payment of money in an aggregate amount in excess of \$75 million, if this same amount remains undischarged for a period of thirty consecutive days during which execution shall not be effectively stayed; and (iv) voluntary or involuntary commencements of any proceedings or petitions seeking our liquidation, reorganization or any other similar relief under any federal, state or foreign bankruptcy, insolvency, receivership or similar law.

Other than the relatively non-restrictive negative covenants and events of default in our credit facility, there are no provisions protecting against a situation where we are unable to terminate an agreement with a counterparty who is facing an impending financial collapse and such collapse may be hastened due to cross-defaults. Also, the credit facility does not contain a material adverse change clause coupled with a lockbox provision; however, the facility does provide that the margin we will pay with respect to borrowings, and the facility fee that we will pay on the total commitment, will vary based on our senior debt credit rating. None of our debt is subject to payment acceleration as a result of any change to our credit ratings.

Commercial Paper Program

In July 2011, in conjunction with the amendment to our revolving credit facility, we increased our commercial paper program to provide for the issuance of up to \$2.2 billion of commercial paper (up from \$2.0 billion). Our unsecured revolving credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

As of December 31, 2011, we had \$644.8 million of commercial paper outstanding with an average interest rate of 0.53%. As of December 31, 2010, we had \$522.1 million of commercial paper outstanding with an average interest rate of 0.67%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital

expansions we made during 2011 and 2010, and in the near term, we expect that our short-term liquidity and financing needs will be met primarily through borrowings made under our commercial paper program.

Long-Term Debt

Our outstanding long-term debt, excluding the value of interest rate swaps, as of December 31, 2011 and 2010 was \$11,159.5 million and \$10,277.4 million, respectively. The balances consisted of the following (in millions):

	December 31,	
	2011	2010
Kinder Morgan Energy Partners, L.P. borrowings:		
6.75% senior notes due March 15, 2011.....	\$ -	\$ 700.0
7.125% senior notes due March 15, 2012.....	450.0	450.0
5.85% senior notes due September 15, 2012	500.0	500.0
5.00% senior notes due December 15, 2013.....	500.0	500.0
5.125% senior notes due November 15, 2014	500.0	500.0
5.625% senior notes due February 15, 2015.....	300.0	300.0
3.50% senior notes due March 1, 2016.....	500.0	-
6.00% senior notes due February 1, 2017.....	600.0	600.0
5.95% senior notes due February 15, 2018.....	975.0	975.0
9.00% senior notes due February 1, 2019(a)	500.0	500.0
6.85% senior notes due February 15, 2020.....	700.0	700.0
5.30% senior notes due September 15, 2020	600.0	600.0
5.80% senior notes due March 1, 2021.....	400.0	400.0
4.15% senior notes due March 1, 2022.....	375.0	-
7.40% senior notes due March 15, 2031.....	300.0	300.0
7.75% senior notes due March 15, 2032.....	300.0	300.0
7.30% senior notes due August 15, 2033.....	500.0	500.0
5.80% senior notes due March 15, 2035.....	500.0	500.0
6.50% senior notes due February 1, 2037.....	400.0	400.0
6.95% senior notes due January 15, 2038.....	1,175.0	1,175.0
6.50% senior notes due September 1, 2039.....	600.0	600.0
6.55% senior notes due September 15, 2040	400.0	400.0
6.375% senior notes due March 1, 2041.....	600.0	-
5.625% senior notes due September 1, 2041	375.0	-
Commercial paper borrowings	644.8	522.1
Subsidiary borrowings:		
Kinder Morgan Operating L.P. "A"-5.40% BP note, due March 31, 2012.....	5.2	10.2
Kinder Morgan Canada Company-5.40% BP note, due March 31, 2012	4.7	9.0
Kinder Morgan Texas Pipeline, L.P.-5.23% senior notes, due January 2, 2014	16.4	23.6
Kinder Morgan Arrow Terminals L.P.-6.0% note due March 28, 2014	2.1	-
Kinder Morgan Liquids Terminals LLC-N.J. Development Revenue Bonds due Jan. 15, 2018 ...	25.0	25.0
Kinder Morgan Columbus LLC-5.50% MS Development Revenue note due Sept. 1, 2022	8.2	8.2
Kinder Morgan Operating L.P. "B"-Jackson-Union Cos. IL Revenue Bonds due April 1, 2024 ..	23.7	23.7
International Marine Terminals-Plaquemines, LA Revenue Bonds due March 15, 2025.....	40.0	40.0
Other miscellaneous subsidiary debt	1.2	1.3
Unamortized debt discount on senior notes	(24.0)	(23.3)
Current portion of long-term debt.....	(1,637.8)	(1,262.4)
Total long-term debt.....	<u>\$ 11,159.5</u>	<u>\$ 10,277.4</u>

- (a) We issued our \$500 million in principal amount of 9.00% senior notes due February 1, 2019 in December 2008. Each holder of the notes has the right to require us to repurchase all or a portion of the notes owned by such holder on February 1, 2012 at a purchase price equal to 100% of the principal amount of the notes tendered by the holder plus accrued and unpaid interest to, but excluding, the repurchase date. On and after February 1, 2012, interest will cease to accrue on the notes tendered for repayment. A holder's exercise of the repurchase option is irrevocable. For more information about these senior notes, see "—Subsequent Event" below.

Kinder Morgan Energy Partners, L.P. Senior Notes

As of December 31, 2011 and 2010, the net carrying value of the various series of our senior notes was \$12,026.0 million and \$10,876.7 million, respectively. For a listing of the various outstanding series of our senior notes, see the table above included in “—Long-Term Debt.” All of our fixed rate senior notes provide that we may redeem the notes 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.

During 2011, we completed two separate public offerings of senior notes. With regard to these offerings, we received proceeds, net of underwriter discounts, as follows: (i) \$1,092.7 million from a March 4, 2011 public offering of a total of \$1.1 billion in principal amount of senior notes, consisting of \$500 million of 3.50% notes due March 1, 2016 and \$600 million of 6.375% notes due March 1, 2041; and (ii) \$743.3 million from an August 17, 2011 public offering of a total of \$750 million in principal amount of senior notes, consisting of \$375 million of 4.15% notes due March 1, 2022 and \$375 million of 5.625% notes due September 1, 2041. We used the proceeds from all of our 2011 debt offerings to reduce the borrowings under our commercial paper program.

On March 15, 2011, we paid \$700 million to retire the principal amount of our 6.75% senior notes that matured on that date. We used both cash on hand and borrowings under our commercial paper program to repay the maturing senior notes.

On May 19, 2010, we completed a public offering of senior notes. We issued a total of \$1 billion in principal amount of senior notes in two separate series, consisting of \$600 million of 5.30% notes due September 15, 2020, and \$400 million of 6.55% notes due September 15, 2040. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of \$993.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

In addition, on November 1, 2010, we paid \$250 million to retire the principal amount of our 7.50% senior notes that matured on that date. We borrowed the necessary funds under our commercial paper program.

Subsidiary Debt

Our subsidiaries are obligors on the following debt. The agreements governing these obligations contain various affirmative and negative covenants and events of default. We do not believe that these provisions will materially affect distributions to our partners.

Kinder Morgan Arrow Terminals L.P. Debt

On January 1, 2010, our subsidiary Kinder Morgan Arrow Terminals L.P. paid the \$5.3 million outstanding principal amount of its Adjustable Rate Industrial Development Revenue Bonds issued by the Illinois Development Finance Authority that matured on that date, and following its repayment, Arrow Terminals L.P. had no outstanding debt.

On April 4, 2011, Kinder Morgan Arrow Terminals, L.P. acquired a parcel of land and a terminal warehouse located in Industry, Pennsylvania from a third party for an aggregate consideration of \$3.3 million, consisting of \$1.2 million in cash and a \$2.1 million promissory note payable. The note principal is payable in three annual payments beginning in March 2012. The note bears interest at 6% per annum, and accrued interest on the unpaid principal amount is due and payable on the due date of each principal installment.

KinderHawk Field Services LLC Credit Facility

On July 1, 2011, immediately following our acquisition of the remaining 50% ownership interest in KinderHawk Field Services LLC that we did not already own (discussed in Note 3 “Acquisitions and Divestitures—Acquisitions—(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC.”), we repaid the outstanding \$154.0 million of borrowings under KinderHawk’s revolving bank credit facility and following this repayment, KinderHawk had no outstanding debt. The revolving bank credit facility was terminated at the time of such repayment.

Kinder Morgan Operating L.P. “A” Debt

Effective January 1, 2007, we acquired the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own. As part of our purchase price consideration, two of our subsidiaries issued a long-term note payable to the seller having a fair value of \$42.3 million. We valued the debt equal to the present value of amounts to be

paid, determined using an annual interest rate of 5.40%. Our subsidiaries Kinder Morgan Operating L.P. “A” and Kinder Morgan Canada Company are the obligors on the note, and the principal amount of the note, along with interest, is due in five annual installments of \$10.0 million beginning March 31, 2008. We paid the fourth installment on March 31, 2011, and as of December 31, 2011, the net present value of the note (representing the outstanding balance included as debt on our accompanying consolidated balance sheet) was \$9.9 million. As of December 31, 2010, the net present value of the note was \$19.2 million.

Kinder Morgan Texas Pipeline, L.P. Debt

Our subsidiary, Kinder Morgan Texas Pipeline, L.P. is the obligor on a series of unsecured senior notes, which were assumed on August 1, 2005 when we acquired a natural gas storage facility located in Liberty County, Texas from a third party. The notes have a fixed annual stated interest rate of 8.85%; however, we valued the debt equal to the present value of amounts to be paid determined using an approximate interest rate of 5.23%. The assumed principal amount, along with interest, is due in monthly installments of approximately \$0.7 million, and the final payment is due January 2, 2014. During 2011, we paid a combined principal amount of \$7.2 million, and as of December 31, 2011, Kinder Morgan Texas Pipeline L.P.’s outstanding balance under the senior notes was \$16.4 million. Additionally, the unsecured senior notes may be prepaid at any time in amounts of at least \$1.0 million and at a price equal to the higher of par value or the present value of the remaining scheduled payments of principal and interest on the portion being prepaid. As of December 31, 2010, the outstanding balance under the notes was \$23.6 million.

Kinder Morgan Liquids Terminals LLC Debt

Our subsidiary Kinder Morgan Liquids Terminals LLC is the obligor on \$25.0 million of Economic Development Revenue Refunding Bonds issued by the New Jersey Economic Development Authority. These bonds have a maturity date of January 15, 2018. Interest on these bonds is computed on the basis of a year of 365 or 366 days, as applicable, for the actual number of days elapsed during Commercial Paper, Daily or Weekly Rate Periods and on the basis of a 360-day year consisting of twelve 30-day months during a Term Rate Period. As of December 31, 2011, the interest rate on these bonds was 0.09%. We have an outstanding letter of credit issued by Citibank in the amount of \$25.4 million that backs-up the \$25.0 million principal amount of the bonds and \$0.4 million of interest on the bonds for up to 46 days computed at 12% on a per annum basis on the principal thereof.

Kinder Morgan Operating L.P. “B” Debt

Our subsidiary Kinder Morgan Operating L.P. “B” is the obligor of a principal amount of \$23.7 million of tax-exempt bonds due April 1, 2024. The bonds were issued by the Jackson-Union Counties Regional Port District, a political subdivision embracing the territories of Jackson County and Union County in the state of Illinois. These variable rate demand bonds bear interest at a weekly floating market rate and are backed-up by a letter of credit issued by Wells Fargo. The bond indenture also contains certain standby purchase agreement provisions which allow investors to put (sell) back their bonds at par plus accrued interest. As of December 31, 2011, the interest rate on these bonds was 0.11%. Our outstanding letter of credit issued by Wells Fargo totaled \$24.1 million, which backs-up a principal amount of \$23.7 million and \$0.4 million of interest on the bonds for up to 55 days computed at 12% per annum on the principal amount thereof.

International Marine Terminals Debt

We own a 66 2/3% interest in the International Marine Terminals (IMT) partnership. The principal assets owned by IMT are dock and wharf facilities financed by the Plaquemines Port, Harbor and Terminal District (Louisiana) \$40.0 million Adjustable Rate Annual Tender Port Facilities Revenue Refunding Bonds (International Marine Terminals Project) Series 1984A and 1984B. As of December 31, 2011, the interest rate on these bonds was 1.28%.

On March 15, 2005, these bonds were refunded and the maturity date was extended from March 15, 2006 to March 15, 2025. No other changes were made under the bond provisions. The bonds are backed by two letters of credit issued by Wells Fargo. On March 19, 2002, an Amended and Restated Letter of Credit Reimbursement Agreement relating to the letters of credit in the amount of \$45.5 million was entered into by IMT and KBC Bank. In connection with that agreement, we agreed to guarantee the obligations of IMT in proportion to our ownership interest. Our obligation is approximately \$30.3 million for principal, plus interest and other fees.

Gulf Opportunity Zone Bonds

To help fund our business growth in the states of Mississippi and Louisiana, we completed the purchase of a combined \$13.2 million in principal amount of tax exempt revenue bonds in two separate transactions in December 2008. To acquire our investment, two of our subsidiaries issued notes with identical terms under the Gulf Opportunity Zone Act of 2005. The notes consisted of the following: (i) \$8.2 million in principal amount of 5.5% Development Revenue Bonds issued by the Mississippi Business Finance Corporation (MBFC), a public, non-profit corporation that coordinates a variety of resources used to assist business and industry in the state of Mississippi; and (ii) \$5.0 million in principal amount of 6.0% Development Revenue Bonds issued by the Louisiana Community Development Authority (LCDA), a political subdivision of the state of Louisiana.

The Mississippi revenue bonds mature on September 1, 2022, and both principal and interest is due in full at maturity. We also hold an option to redeem in full (and settle the note payable to MBFC) the principal amount of bonds held by us without penalty after one year. We redeemed the Louisiana revenue bonds in December 2010 (by settling our \$5.0 million note payable to LCDA), and we replaced this investment with a new investment of \$100.0 million in principal amount of Development Revenue Bonds that mature on December 1, 2040 and pay interest at a rate equal to one-month LIBOR plus 1.75%. We paid for this investment by issuing a \$100.0 million note payable to LCDA with identical terms, and for this bond issuance, we elected to offset our borrowing against the investment we acquired.

Maturities of Debt

The scheduled maturities of our outstanding debt, excluding the value of interest rate swaps, as of December 31, 2011, are summarized as follows (in millions):

Year	Commitment
2012.....	\$ 1,637.8
2013.....	508.2
2014.....	501.3
2015.....	299.9
2016.....	499.9
Thereafter	9,350.2
Total	<u>\$ 12,797.3</u>

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 13 “Risk Management—Interest Rate Risk Management.”

Subsequent Event

On February 1, 2012, we repaid a principal amount of less than \$0.1 million of our 9.00% senior notes due February 1, 2019 pursuant to debtholder one-time elections requiring us to repurchase notes owned by such holders at a purchase price equal to 100% of the principal amount of the notes tendered by the holder plus accrued and unpaid interest to, but excluding, the repurchase date of February 1, 2012.

9. Employee Benefits

Pension and Postretirement Benefit Plans

Two of our subsidiaries, Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension plans for eligible Trans Mountain pipeline system employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements (which provide pension benefits in excess of statutory limits), and defined contributory plans. These subsidiaries also provide postretirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and postretirement benefit plans for 2011, 2010 and 2009 were \$6.9 million, \$3.9 million and \$2.9 million, respectively, recognized ratably over each year. As of December 31, 2011, we estimate our overall net periodic pension and postretirement benefit costs for these plans for the year 2012 will be approximately \$11.3 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. Furthermore, we expect to contribute approximately \$8.9 million to these benefit plans in 2012.

Additionally, our subsidiary SFPP, L.P. has incurred certain liabilities for postretirement benefits. SFPP provides medical and life insurance benefits to certain current employees, their covered dependents, and their beneficiaries. SFPP also provides the same benefits to former salaried employees and will continue to fund these costs for those employees currently in the plan during their retirement years; however, SFPP's postretirement benefit plan is frozen and no additional participants may join the plan. Benefits under the SFPP postretirement benefit plan are provided by the Burlington Northern Santa Fe railroad and we reimburse BNSF for the costs of the plan. Our net periodic benefit cost for the SFPP postretirement benefit plan for 2011 was \$0.1 million, and for each of the years ended December 31, 2010 and 2009, our net periodic benefit cost was a credit of less than \$0.1 million. The credits in 2010 and 2009 resulted in increases to income, largely due to amortizations of an actuarial gain and a negative prior service cost. As of December 31, 2011, we estimate our overall net periodic postretirement benefit cost for the SFPP postretirement benefit plan for the year 2012 will be approximately \$0.1 million; however, this estimate could change if a future significant event would require a remeasurement of liabilities. In addition, we expect to contribute approximately \$0.3 million to this postretirement benefit plan in 2012.

As of December 31, 2011 and 2010, the recorded value of our pension and postretirement benefit obligations for both the Trans Mountain pension and postretirement benefit plans and the SFPP postretirement benefit plan was a combined \$70.0 million and \$44.8 million, respectively. We consider our overall pension and postretirement benefit liability exposure and the fair value of our pension and postretirement plan assets to be minimal in relation to the value of our total consolidated assets and net income.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily our acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, 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 for each of the years ended December 31, 2011, 2010 and 2009 were \$12.3 million, \$10.3 million and \$8.4 million, respectively. We consider our overall multi-employer pension plan liability exposure to be minimal in relation to the value of our total consolidated assets and net income.

Kinder Morgan Savings Plan

The Kinder Morgan Savings Plan is a defined contribution 401(k) plan. The plan permits all full-time employees of KMI and KMGP Services Company, Inc. to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. As an additional benefit to all participants, an option also exists to make after-tax "Roth" contributions (Roth 401(k) option) to a separate Savings Plan participant account, and certain employees' contributions are based on collective bargaining agreements. Currently, our general partner contributes an amount equal to 5% of base compensation per year for most plan participants (described below). The contributions are made each pay period on behalf of each eligible employee.

Participants may direct the investment of their contributions and all employer contributions, including discretionary contributions, into a variety of investments. Plan assets are held and distributed pursuant to a trust agreement. The total amount charged to expense for the Kinder Morgan Savings Plan was \$16.5 million during 2011, \$13.3 million during 2010, and \$12.1 million during 2009.

Employer contributions for employees vest on the second anniversary of the date of hire. Effective October 1, 2005, for new employees of our Terminals segment, a tiered employer contribution schedule was implemented. This tiered schedule provides for employer contributions of 1% for service less than one year, 2% for service between one and two years, 3% for services between two and five years, and 4% for service of five years or more. All employer contributions for Terminals employees hired after October 1, 2005 vest on the third anniversary of the date of hire.

At its July 2010 meeting, Mr. Richard D. Kinder and KMR's compensation committee approved a special contribution of an additional 1% of base pay into the Savings Plan for each eligible employee (increasing our general partner's contributions from an amount of 4% of base compensation per year for most plan participants to 5% of base compensation per year). Each eligible employee received the additional 1% company contribution based on eligible base pay each pay period beginning with the first pay period of August 2010 and continuing through the last pay period of July 2011. The additional 1% contribution did not change or otherwise impact the previous 4% contribution that eligible employees received and it vested according to the same vesting schedule described in the preceding paragraph.

At its January 2011 meeting, Mr. Richard D. Kinder and KMR's compensation committee decided to make this special contribution of an additional 1% of base pay a permanent contribution into the Savings Plan for each eligible employee. Accordingly, beginning with the first pay period of August 2011, our general partner now contributes an amount equal to 5% of base compensation per year on behalf of each eligible employee. This change was made to assist employees in providing financial security for retirement without the risk of the 1% variable factor. For employees of our Terminals business segment, the tiered employer contributions described above also increased by 1% beginning with the first pay period of August 2011.

Cash Balance Retirement Plan

Employees of KMGP Services Company, Inc. and KMI are also eligible to participate in a Cash Balance Retirement Plan. Certain employees continue to accrue benefits through a career-pay formula ("grandfathered" according to age and years of service on December 31, 2000), or collective bargaining arrangements. All other employees accrue benefits through a personal retirement account in the Cash Balance Retirement Plan. Under the plan, KMI credits each participating employee's personal retirement account an amount equal to 3% of eligible compensation every pay period. Currently, interest is credited to the personal retirement accounts at a rate equal to the five-year U.S. Treasury note rate plus 0.25% (described below). Employees become fully vested in the plan after three years, and they may take a lump sum distribution upon termination of employment or retirement.

In February 2009, KMI amended the plan in order to reduce its rate of future benefit accruals effective April 12, 2009. Beginning on that date, and continuing through the last pay period of December 2009, KMI ceased making contribution credits to the accounts of all participating employees of KMGP Services, Inc. and KMI under the cash balance portion of the plan, except to the extent the terms of an applicable collective bargaining agreement required contribution credits be made. However, KMI continued to credit interest to employees' personal retirement accounts, and effective January 1, 2010, all contribution credits on behalf of participating employees resumed.

Effective January 1, 2011, KMI amended the plan and began crediting each participating employee's personal retirement account for interest at a rate equal to the five-year U.S. Treasury note rate plus 0.25%. Prior to this amendment, interest was credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. This interest rate credit change allows KMI to invest the plan's assets in a manner that preserves capital and controls volatility. Furthermore, the new interest rate complies with the safe harbor regulations as defined by the U.S. Department of Labor and is expected to reduce the plan's long-term cost. KMI continues to credit 3% of employees' eligible compensation to their personal retirement accounts.

10. Partners' Capital

Limited Partner Units

As of December 31, 2011 and 2010, our partners' capital included the following limited partner units:

	December 31,	
	2011	2010
Common units.....	232,677,222	218,880,103
Class B units	5,313,400	5,313,400
i-units	98,509,389	91,907,987
Total limited partner units	<u>336,500,011</u>	<u>316,101,490</u>

The total limited partner units represent our limited partners' interest and an effective 98% interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its right to receive incentive distributions.

As of December 31, 2011, our total common units consisted of 216,306,794 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2010, our total common units consisted of 202,509,675 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner.

As of both December 31, 2011 and December 31, 2010, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange.

As of both December 31, 2011 and 2010, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. In accordance with its limited liability company agreement, KMR's activities are restricted to being a limited partner in us, and to controlling and managing our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Through the combined effect of the provisions in our partnership agreement and the provisions of KMR's limited liability company agreement, the number of outstanding KMR shares and the number of our i-units will at all times be equal.

Under the terms of our partnership agreement, we agreed that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as our i-units. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we will issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units. If additional units are distributed to the holders of our common units, we will issue an equivalent amount of i-units to KMR based on the number of i-units it owns.

Based on the preceding, during the year ended December 31, 2011, KMR received distributions of 6,601,402 i-units. These additional i-units distributed were based on the \$4.58 per unit distributed to our common unitholders during 2011. During the year ended December 31, 2010, KMR received distributions of 6,369,724 i-units. These additional i-units distributed were based on the \$4.32 per unit distributed to our common unitholders during 2010. During the year ended December 31, 2009, KMR received distributions of 7,540,357 i-units. These additional i-units distributed were based on the \$4.20 per unit distributed to our common unitholders during 2009.

Equity Issuances

2011 Issuances

On February 25, 2011, we entered into a second amended and restated equity distribution agreement with UBS Securities LLC (UBS) to provide for the offer and sale of common units having an aggregate offering price of up to \$1.2 billion (up from an aggregate offering price of up to \$600 million under our first amended and restated agreement) from time to time through UBS, as our sales agent. Sales of the units will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we also may sell common units to UBS as principal for its own account at a price agreed upon at the time of the sale. Any sale of common units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS.

This equity distribution agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through UBS, on a daily basis or otherwise as we and UBS agree. UBS will then use its reasonable efforts to sell, as our sales agent and on our behalf, all of the designated common units. We may instruct UBS not to sell common units if the sales cannot be effected at or above the price designated by us in any such instruction. Either we or UBS may suspend the offering of common units pursuant to the agreement by notifying the other party.

In 2011, we issued 5,764,708 of our common units pursuant to our equity distribution agreement. After commissions of \$3.2 million, we received net proceeds from the issuance of these common units of \$421.4 million. We used the proceeds to reduce the borrowings under our commercial paper program.

We also completed the following equity issuances in 2011:

- On June 10, 2011, we issued 324,961 common units as part of our purchase price for the petroleum coke terminal assets we acquired from TGS Development, L.P. We valued the common units at \$23.7 million, determining the units' value based on the \$73.01 closing market price of the common units on the New York Stock Exchange on the June 10, 2011 acquisition date (for more information on this acquisition, see Note 3 "Acquisitions and Divestitures—Acquisitions—(15) TGS Development, L.P. Terminal Acquisition;" and

- On June 17, 2011, we issued, in a public offering, 6,700,000 of our common units at a price of \$71.44 per unit, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 1,005,000 common units from us on the same terms and conditions, and upon the underwriters' exercise of this option in full, we issued the additional 1,005,000 common units on June 27, 2011. We received net proceeds, after deducting the underwriter discount, of \$533.9 million from the issuance of these 7,705,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

2010 Issuances

In 2010, we issued 3,902,225 of our common units pursuant to our equity distribution agreement with UBS. After commissions of \$2.0 million, we received net proceeds from the issuance of these common units of \$266.3 million. We used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

We also completed the following equity issuances in 2010:

- On January 15, 2010, we issued 1,287,287 common units as a portion of our purchase price for additional ethanol handling terminal assets we acquired from US Development Group LLC. We valued the common units at \$81.7 million, determining the units' value based on the \$63.45 closing market price of the common units on the New York Stock Exchange on the January 15, 2010 acquisition date (for more information on this acquisition, see Note 3 "Acquisitions and Divestitures—Acquisitions—(5) USD Terminal Acquisition;")
- On May 7, 2010, we issued, in a public offering, 6,500,000 of our common units at a price of \$66.25 per unit, less commissions and underwriting expenses. After deducting the underwriter discount, we received net proceeds of \$417.4 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility; and
- On July 2, 2010, we completed an offering of 1,167,315 of our common units at a price of \$64.25 per unit in a privately negotiated transaction. We received net proceeds of \$75.0 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed, and we determine the allocation of incentive distributions to our general partner by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement.

For each of the years ended December 31, 2011, 2010 and 2009, we declared distributions of \$4.61, \$4.40 and \$4.20 per unit, respectively. Cash distributions paid to all partners, consisting of our common and Class B unitholders, our general partner and noncontrolling interests, totaled \$2,243.6 million in 2011, \$1,826.6 million in 2010 and \$1,771.9 million in 2009. In addition, we made distributions of additional i-units in each of these years to KMR as discussed under "—Limited Partner Units" above. Distributions for the fourth quarter of each year are declared and paid during the first quarter of the following year. The year-to-year increases in distributions paid reflect the increase in amounts distributed per unit as well as the issuance of additional units; however, the overall increases in distributions paid in 2011 versus 2010, and in 2010 versus 2009, were partially offset by decreases in the incentive distribution we paid to our general partner in both 2011 and 2010, as discussed following.

Our general partner's incentive distribution that we declared for each of the years 2011, 2010 and 2009 was \$1,174.1 million, \$880.5 million and \$932.3 million, respectively, while the incentive distribution we paid to our general partner in 2011, 2010 and 2009 was \$1,146.4 million, \$848.2 million and \$906.5 million, respectively. The general partner's incentive distribution we paid in 2011 was reduced by a waived incentive amount equal to \$28.4 million related to common units issued to finance a portion of our May 2010 KinderHawk Field Services LLC acquisition. Beginning with our distribution payments for the quarterly period ended June 30, 2010, our general partner has agreed not to take incentive distributions related to this acquisition of our initial 50% interest in KinderHawk through year-end 2011. For

more information about this acquisition, see Note 3 “Acquisitions and Divestitures—Acquisitions—(8) KinderHawk Field Services LLC.”

The general partner’s incentive distribution we paid in 2010 was affected by (i) a reduced incentive amount of \$168.3 million due to a portion of our available cash distribution for the second quarter of 2010 being a distribution of cash from interim capital transactions, rather than a distribution of cash from operations (including the general partner’s 2% general partner interest, its total cash distributions were reduced by \$170.0 million); and (ii) the waived incentive amount equal to \$11.1 million related to our May 2010 KinderHawk acquisition. Our distribution of cash for the second quarter of 2010 (which we paid in the third quarter of 2010) from interim capital transactions totaled \$177.1 million (approximately \$0.56 per limited partner unit), and pursuant to the provisions of our partnership agreement, our general partner receives no incentive distribution on distributions of cash from interim capital transactions. Accordingly, this distribution from interim capital transactions helped preserve our cumulative excess cash coverage. Cumulative excess cash coverage is cash from operations generated since our inception in excess of cash distributions paid.

In addition, there was no practical impact to our limited partners from this distribution of cash from interim capital transactions because (i) the cash distribution to our limited partners for the quarter did not change; (ii) fewer dollars in the aggregate were distributed (because there was no incentive distribution paid to our general partner related to the portion of the quarterly distribution that was a distribution of cash from interim capital transactions); and (iii) our general partner, in this instance, agreed to waive any resetting of the incentive distribution target levels, as would otherwise occur according to our partnership agreement.

For further information about our partnership distributions, see Note 11 “Related Party Transactions—Partnership Interests and Distributions.”

Subsequent Events

In early January 2012, we issued 160,510 of our common units for the settlement of sales made on or before December 31, 2011 pursuant to our equity distribution agreement with UBS. After commissions of \$0.1 million, we received net proceeds of \$13.4 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On January 18, 2012, we declared a cash distribution of \$1.16 per unit for the quarterly period ended December 31, 2011. This distribution was paid on February 14, 2012, to unitholders of record as of January 31, 2012. Since this distribution was declared after the end of the quarter, no amount is shown in our December 31, 2011 balance sheet as a distribution payable.

Our common unitholders and our Class B unitholder received cash. KMR, our sole i-unitholder, received a distribution in the form of additional i-units based on the \$1.16 distribution per common unit. The number of i-units distributed was 1,464,145. For each outstanding i-unit that KMR held, a fraction of an i-unit (0.014863) was issued. The fraction was determined by dividing:

- \$1.16, the cash amount distributed per common unit

by

- \$78.046, the average of KMR’s limited liability shares’ closing market prices from January 12-26, 2012, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

This February 14, 2012 distribution included an incentive distribution to our general partner in the amount of \$302.3 million. This incentive distribution was affected by a waived incentive distribution amount equal to \$7.2 million related to common units issued to finance a portion of our May 2010 KinderHawk acquisition. Furthermore, to support our acquisition of the remaining 50% interest in KinderHawk effective July 1, 2011, our general partner has agreed to waive incentive distribution amounts equal to \$25.5 million for 2012 and \$3.5 million for 2013. For more information about this acquisition, see Note 3 “Acquisitions and Divestitures—Acquisitions—(16) KinderHawk Field Services LLC and EagleHawk Field Services LLC.”

11. Related Party Transactions

General and Administrative Expenses

KMGP Services Company, Inc., a subsidiary of our general partner, provides employees and Kinder Morgan Services LLC, a wholly owned subsidiary of KMR, provides centralized payroll and employee benefits services to (i) us; (ii) our operating partnerships and subsidiaries; (iii) our general partner; and (iv) KMR (collectively referred to in this note as the Group). Employees of KMGP Services Company, Inc. are assigned to work for one or more members of the Group. The direct costs of all compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated and charged by Kinder Morgan Services LLC to the appropriate members of the Group, and the members of the Group reimburse Kinder Morgan Services LLC for their allocated shares of these direct costs. There is no profit or margin charged by Kinder Morgan Services LLC to the members of the Group. The administrative support necessary to implement these payroll and benefits services is provided by the human resource department of KMI, and the related administrative costs are allocated to members of the Group in accordance with existing expense allocation procedures.

The effect of these arrangements is that each member of the Group 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. Pursuant to our limited partnership agreement, we provide reimbursement for our share of these administrative costs and such reimbursements will be accounted for as described above. Additionally, we reimburse KMR with respect to costs incurred or allocated to KMR in accordance with our limited partnership agreement, the delegation of control agreement among our general partner, KMR, us and others, and KMR's limited liability company agreement.

The named executive officers of our general partner and KMR and other employees that provide management or services to both KMI and the Group are employed by KMI. Additionally, other KMI employees assist in the operation of certain of our assets (discussed below in "—Operations"). These employees' expenses are allocated without a profit component between KMI on the one hand, and the appropriate members of the Group, on the other hand.

Non-Cash Compensation Expenses

For accounting purposes, KMI was required to allocate to us a portion of its 2007 going-private transaction-related amounts, and it is required to recognize compensation expense in connection with their Class A-1 and Class B units over the expected life of such units and allocate to us a portion of these going-private transaction-related amounts. These units were issued prior to the conversion of Kinder Morgan Holdco LLC to KMI. As a subsidiary of KMI, we are required to recognize the allocated amounts as expense on our income statements; however, we have no obligation and we do not expect to pay any amounts related to these going-private transaction-related expenses. Accordingly, we recognize the unpaid amounts as contributions to "Total Partners' Capital" on our balance sheet. For each of the years 2011, 2010 and 2009, we recognized non-cash compensation expense of \$2.8 million, \$4.6 million and \$5.7 million, respectively, due to certain going-private transaction expenses allocated to us from KMI in connection with KMI's May 2007 going-private transaction. We do not expect KMI to allocate any further going-private transaction-related expenses to us.

Additionally, in the first quarter of 2011, KMI allocated to us certain non-cash compensation expenses totaling \$87.1 million associated with a one-time special cash bonus payment that was paid to non-senior management employees in May 2011. However, we do not have any obligation, nor did we pay any amounts related to these compensation expenses, and since we were not responsible for paying these expenses, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet.

Partnership Interests and Distributions

General

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. Available Cash consists generally of all of our cash receipts, including cash received by our operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to the former general partner of SFPP, L.P. in respect of its remaining 0.5% interest in SFPP.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to KMR, subject to the approval of our general partner in certain cases, to establish, maintain and adjust reserves for the proper conduct of our business, which might include reserves for matters such as future operating expenses, debt service,

sustaining capital expenditures and rate refunds, and for distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When KMR determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Our general partner and owners of our common units and Class B units receive distributions in cash, while KMR, the sole owner of our i-units, receives distributions in additional i-units. We do not distribute cash to i-unit owners (KMR) but instead retain the cash for use in our business. However, the cash equivalent of distributions of i-units is treated as if it had actually been distributed for purposes of determining the distributions to our general partner. Each time we make a distribution, the number of i-units owned by KMR and the percentage of our total units owned by KMR increase automatically under the provisions of our partnership agreement.

Pursuant to our partnership agreement, distributions to unitholders are characterized either as distributions of cash from operations or as distributions of cash from interim capital transactions. This distinction affects the distributions to owners of common units, Class B units and i-units relative to the distributions to our general partner.

Cash from Operations. Cash from operations generally refers to our cash balance on the date we commenced operations, plus all cash generated by the operation of our business, after deducting related cash expenditures, net additions to or reductions in reserves, debt service and various other items.

Cash from Interim Capital Transactions. Cash from interim capital transactions will generally result only from distributions that are funded from borrowings, sales of debt and equity securities and sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets and assets disposed of in the ordinary course of business.

Rule for Characterizing Distributions. Generally, all available cash distributed by us from any source will be treated as distributions of cash from operations until the sum of all available cash distributed equals the cumulative amount of cash from operations actually generated from the date we commenced operations through the end of the calendar quarter prior to that distribution. Any distribution of available cash which, when added to the sum of all prior distributions, is in excess of the cumulative amount of cash from operations, will be considered a distribution of cash from interim capital transactions until the initial common unit price is fully recovered as described below under “—Allocation of Distributions from Interim Capital Transactions.” For purposes of calculating the sum of all distributions of available cash, the total equivalent cash amount of all distributions of i-units to KMR, as the holder of all i-units, will be treated as distributions of available cash, even though the distributions to KMR are made in additional i-units rather than cash and we retain this cash and use it in our business. To date, all of our available cash distributions, other than a \$177.1 million distribution of cash from interim capital transactions for the second quarter of 2010 (paid in the third quarter of 2010), have been treated as distributions of cash from operations.

Allocation of Distributions from Operations. Cash from operations for each quarter will be distributed effectively as follows:

- first, 98% to the owners of all classes of units pro rata and 2% to our general partner until the owners of all classes of units have received a total of \$0.15125 per unit in cash or equivalent i-units for such quarter;
- second, 85% of any available cash then remaining to the owners of all classes of units pro rata and 15% to our general partner until the owners of all classes of units have received a total of \$0.17875 per unit in cash or equivalent i-units for such quarter;
- third, 75% of any available cash then remaining to the owners of all classes of units pro rata and 25% to our general partner until the owners of all classes of units have received a total of \$0.23375 per unit in cash or equivalent i-units for such quarter; and
- fourth, 50% of any available cash then remaining to the owners of all classes of units pro rata, to owners of common units and Class B units in cash and to owners of i-units in the equivalent number of i-units, and 50% to our general partner.

Allocation of Distributions from Interim Capital Transactions. Any distribution by us of available cash that would constitute cash from interim capital transactions would be distributed effectively as follows:

- 98% to all owners of common units and Class B units pro rata in cash and to the holders of i-units in equivalent i-units; and

- 2% to our general partner, until we have distributed cash from this source in respect of a common unit outstanding since our original public offering in an aggregate amount per unit equal to the initial common unit price of \$5.75, as adjusted for splits.

As cash from interim capital transactions is distributed, it would be treated as if it were a repayment of the initial public offering price of the common units. To reflect that repayment, the first three distribution target levels of cash from operations (described above) would be adjusted downward proportionately by multiplying each distribution target level amount by a fraction, the numerator of which is the unrecovered initial common unit price immediately after giving effect to that distribution and the denominator of which is the unrecovered initial common unit price immediately prior to giving effect to that distribution. When the initial common unit price is fully recovered, then each of the first three distribution target levels will have been reduced to zero, and thereafter, all distributions of available cash from all sources will be treated as if they were cash from operations and available cash will be distributed 50% to all classes of units pro rata (with the distribution to i-units being made instead in the form of i-units), and 50% to our general partner. With respect to the portion of our distribution of available cash for the second quarter of 2010 that was from interim capital transactions, our general partner waived this resetting of the distribution target levels.

Kinder Morgan G.P., Inc.

Kinder Morgan G.P., Inc. serves as our sole general partner. Pursuant to our partnership agreement, our general partner's interests represent a 1% ownership interest in us, and a direct 1.0101% ownership interest in each of our five operating partnerships. Collectively, our general partner owns an effective 2% interest in our operating partnerships, excluding incentive distributions rights as follows:

- its 1.0101% direct general partner ownership interest (accounted for as a noncontrolling interest in our consolidated financial statements); and
- its 0.9899% ownership interest indirectly owned via its 1% ownership interest in us.

As of December 31, 2011, our general partner owned 1,724,000 common units, representing approximately 0.51% of our outstanding limited partner units. For information on distributions paid to our general partner, see Note 10 "Partners' Capital—Income Allocation and Declared Distributions."

Kinder Morgan, Inc.

KMI remains the sole indirect common stockholder of our general partner. Also, as of December 31, 2011, KMI directly owned 10,852,788 common units, indirectly owned 5,313,400 Class B units and 5,517,640 common units through its consolidated affiliates (including our general partner), and owned 14,055,426 KMR shares, representing an indirect ownership interest of 14,055,426 i-units. Together, these units represented approximately 10.6% of our outstanding limited partner units.

Including both its general and limited partner interests in us, at the 2011 distribution level, KMI received approximately 50% of all quarterly distributions of available cash from us, with approximately 44% attributable to its general partner interest and the remaining 6% attributable to its limited partner interest. These percentages were impacted slightly due to the general partner's waiver of certain incentive distribution amounts, as described in Note 10 "Partners' Capital—Income Allocation and Declared Distributions."

Kinder Morgan Management, LLC

As of December 31, 2011, KMR, our general partner's delegate, remained the sole owner of our 98,509,389 i-units.

Asset Acquisitions and Sales

Mr. C. Berdon Lawrence, a non-management director on the boards of our general partner and KMR until July 20, 2011, is also Chairman Emeritus of the Board of Kirby Corporation. On February 9, 2011, we sold a marine vessel to Kirby Corporation's subsidiary Kirby Inland Marine, L.P., and additionally, we and Kirby Inland Marine L.P. formed a joint venture named Greens Bayou Fleeting, LLC. For more information about these transactions, see Note 3 "Acquisitions and Divestitures—Divestitures—Megafleet Towing Co., Inc. Assets."

From time to time in the ordinary course of business, we buy and sell pipeline and related services from KMI and its subsidiaries. Such transactions are conducted in accordance with all applicable laws and regulations and on an arms' length basis consistent with our policies governing such transactions. In conjunction with our acquisition of (i) certain

Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; and (ii) all of the ownership interest in TransColorado Gas Transmission Company LLC from two wholly-owned subsidiaries of KMI on November 1, 2004, KMI agreed to indemnify us and our general partner with respect to approximately \$733.5 million of our debt. KMI would be obligated to perform under this indemnity only if we are unable, and/or our assets were insufficient to satisfy our obligations.

Operations

Natural Gas Pipelines and Products Pipelines Business Segments

KMI (or its subsidiaries) operates and maintain for us the assets comprising our Natural Gas Pipelines business segment, as well as our Products Pipelines business segment's 50%-owned Cypress Pipeline (we sold a 50% ownership interest in the Cypress Pipeline on October 1, 2010, described in Note 3 "Acquisitions and Divestitures—Divestitures—Cypress Interstate Pipeline LLC"). Pursuant to the applicable underlying agreements, we pay (reimburse) KMI for the actual corporate general and administrative expenses incurred in connection with the operation of these assets. The combined amounts paid to KMI for corporate general and administrative costs incurred were \$70.6 million for 2011, \$55.6 million for 2010 and \$46.5 million for 2009. We believe the amounts paid to KMI for the services it provided each year fairly reflect the value of the services performed; however, due to the nature of the allocations, these reimbursements may not exactly match the actual time and overhead spent. We also reimburse KMI for operating and maintenance costs and capital expenditures incurred with respect to our assets.

Our subsidiary Kinder Morgan NatGas Operator LLC operates the Rockies Express and the Midcontinent Express natural gas pipeline systems pursuant to two separate operating agreements. Under the Rockies Express agreement, it is reimbursed for its costs and receives a management fee of 1%, based on Rockies Express' operating income, less all depreciation and amortization expenses. In 2011, 2010 and 2009, it received management fees of \$5.6 million, \$5.4 million and \$4.0 million, respectively. Kinder Morgan NatGas Operator LLC operates the Midcontinent Express pipeline system according to the provisions of an operating agreement entered into in March 2007. It is reimbursed for its operating costs; however, it receives no special management fees according to this agreement.

In addition, we purchase natural gas transportation and storage services from Natural Gas Pipeline Company of America LLC and certain affiliates, collectively referred to as NGPL. KMI owns a 20% ownership interest in NGPL and accounts for its investment under the equity method of accounting. Pursuant to the provisions of a 15-year operating agreement that was entered into in 2008, KMI continues to operate NGPL's assets. For each of the years 2011, 2010 and 2009, expenses related to NGPL totaled \$8.2 million, \$7.8 million and \$8.8 million, respectively, and we included these expense amounts within the caption "Gas purchases and other costs of sales" in our accompanying consolidated statements of income.

CO₂ Business Segment

During 2010 and 2009, Kinder Morgan Power Company, a subsidiary of KMI, operated and maintained for us the power plant we constructed at the SACROC oil field unit, located in the Permian Basin area of West Texas. The power plant provides nearly half of SACROC's current electricity needs. Pursuant to the contract, Kinder Morgan Power Company incurred the costs and expenses related to operating and maintaining the power plant for the production of electrical energy at the SACROC field. Such costs included supervisory personnel and qualified operating and maintenance personnel in sufficient numbers to accomplish the services provided in accordance with good engineering, operating and maintenance practices. Our subsidiary Kinder Morgan Production Company fully reimbursed Kinder Morgan Power Company's expenses, including all agreed-upon labor costs.

In addition, Kinder Morgan Production Company was responsible for processing and directly paying invoices for fuels utilized by the plant. Other materials, including but not limited to lubrication oil, hydraulic oils, chemicals, ammonia and any catalyst were purchased by Kinder Morgan Power Company and invoiced monthly as provided by the contract, if not paid directly by Kinder Morgan Production Company. The amounts paid to Kinder Morgan Power Company in 2010 and 2009 for operating and maintaining the power plant were \$7.6 million and \$5.4 million, respectively. Furthermore, we believe the amounts paid to Kinder Morgan Power Company for the services they provided each year fairly reflected the value of the services performed. Our operating contract with Kinder Morgan Power Company expired on December 31, 2010, and effective January 1, 2011, Kinder Morgan Production Company began operating the power plant.

Terminals Business Segment

For services in the ordinary course of Kirby Corporation's and our Terminals segment's businesses, Kirby Corporation received payments from our subsidiaries totaling \$38,729, \$39,828 and \$18,878 in 2011, 2010 and 2009, respectively, and Kirby made payments, in 2011, to our subsidiaries totaling \$44,615.

Risk Management

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

Our commodity-related risk management activities are monitored by our risk management committee, which is a separately designated standing committee whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of business. Our risk management committee is charged with the review and enforcement of our management's risk management policy. The committee is comprised of 18 executive-level employees of KMI or KMGP Services Company, Inc. whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of our businesses. The committee is chaired by our President and is charged with the following three responsibilities: (i) establish and review risk limits consistent with our risk tolerance philosophy; (ii) recommend to the audit committee of our general partner's delegate any changes, modifications, or amendments to our risk management policy; and (iii) address and resolve any other high-level risk management issues.

For more information on our risk management activities see Note 13.

KM Insurance, Ltd.

KM Insurance, Ltd. is a Class 2 Bermuda insurance company and wholly-owned subsidiary of KMI. The sole business of KM Insurance is to issue policies for KMI and us to secure the deductible portion of our workers compensation, automobile liability, and general liability policies placed in the commercial insurance market. We accrue for the cost of insurance and include these costs within our related party general and administrative expenses. For each of the years 2011, 2010 and 2009, these expenses totaled \$8.8 million, \$8.6 million and \$8.4 million, respectively.

Derivative Counterparties

As a result of KMI's going-private transaction in May 2007, a number of individuals and entities became significant investors in KMI, and by virtue of the size of its ownership interest in KMI, one of those investors—Goldman Sachs Capital Partners and certain of its affiliates—remains a "related party" (as defined by U.S. generally accepted accounting principles) to us as of December 31, 2011. Goldman Sachs has also acted in the past, and may act in the future, as an underwriter for equity and/or debt issuances for us, and Goldman Sachs effectively owned 49% of the terminal assets we acquired from US Development Group LLC in January 2010.

In addition, we conduct energy commodity risk management activities in the ordinary course of implementing our risk management strategies in which the counterparty to certain of our derivative transactions is an affiliate of Goldman Sachs, and in conjunction with these activities, we are a party (through one of our subsidiaries engaged in the production of crude oil) to a hedging facility with J. Aron & Company/Goldman Sachs. The hedging facility requires us to provide certain periodic information, but does not require the posting of margin. As a result of changes in the market value of our derivative positions, we have created both amounts receivable from and payable to Goldman Sachs affiliates.

The following table summarizes the fair values of our energy commodity derivative contracts that are (i) associated with commodity price risk management activities with J. Aron & Company/Goldman Sachs; and (ii) included within "Fair value of derivative contracts" on our accompanying consolidated balance sheets as of December 31, 2011 and 2010 (in millions):

	December 31, 2011	December 31, 2010
Derivatives – asset/(liability)		
Current assets	\$ 8.6	\$ -
Noncurrent assets	\$ 18.2	\$ 12.7
Current liabilities.....	\$ (64.3)	\$ (221.4)
Noncurrent liabilities.....	\$ (9.6)	\$ (57.5)

Notes Receivable

Plantation Pipe Line Company

We own a 51.17% equity interest in Plantation Pipe Line Company. An affiliate of ExxonMobil owns the remaining 48.83% interest. In July 2004, Plantation repaid a \$10 million note outstanding and \$175 million in outstanding commercial paper borrowings with funds of \$190 million borrowed from its owners. We loaned Plantation \$97.2 million, which corresponds to our 51.17% ownership interest, in exchange for a seven year note receivable bearing interest at the rate of 4.72% per annum.

On July 20, 2011, we, ExxonMobil, and Plantation Pipe Line Company amended the term loan agreement covering this note receivable to (i) reduce the aggregate loan amount to \$100.0 million following payments of \$57.9 million made by Plantation to ExxonMobil and us on July 20, 2011; (ii) extend the maturity of the note from July 20, 2011 to July 20, 2016; (iii) allow for pre-payment of all or any portion of the principal amount of the loan without a premium penalty; and (iv) reduce the interest rate on the note from 4.72% per annum to 4.25% per annum. Following the July 20, 2011 payments to both us and ExxonMobil, the note provides for semiannual payments of principal and interest on December 31 and June 30 each year beginning on December 31, 2011, with a final principal payment of \$87.8 million due on July 20, 2016.

During each of the years ended December 31, 2011 and 2010, we received combined principal repayments of \$31.4 million and \$2.7 million, respectively, and as of December 31, 2011, our 51.17% portion of the outstanding principal amount of the note was \$50.7 million. We included \$1.2 million of this note receivable balance within “Accounts, notes and interest receivable, net,” on our accompanying consolidated balance sheet, and the remaining outstanding balance within “Notes Receivable.” As of December 31, 2010, the outstanding note receivable balance was \$82.1 million, and we included this amount within “Accounts, notes and interest receivable, net,” on our accompanying consolidated balance sheet.

Express US Holdings LP

In conjunction with the acquisition of our 33 1/3% equity ownership interest in the Express pipeline system from KMI on August 28, 2008, we acquired a long-term investment in a C\$113.6 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. The debenture is (i) denominated in Canadian dollars; (ii) due in full on January 9, 2023; (iii) bears interest at the rate of 12.0% per annum; and (iv) provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year. As of December 31, 2011 and December 31, 2010, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was \$111.7 million and \$114.2 million, respectively, and we included these amounts within “Notes receivable” on our accompanying consolidated balance sheets.

River Consulting, LLC

In conjunction with the sale of our 51% equity ownership interest in River Consulting, LLC and Devco USA, L.L.C. (discussed in Note 3 “Acquisitions and Divestitures—Divestitures—River Consulting, LLC and Devco USA, L.L.C.”), we extended separate lines of credit to River Consulting and Devco, allowing them to borrow from us an aggregate amount of \$3.0 million for working capital purposes. The lines of credit expire on December 31, 2012, and provide for maximum advances of \$2.7 million to River Consulting and \$0.3 million to Devco. Advances by us pursuant to these lines of credit are evidenced by notes that bear interest at the rate of 9.5% per annum. The notes provide for monthly payments of interest and allow for prepayment of principal borrowings. As of December 31, 2011, River Consulting had borrowed \$0.1 million under its line of credit agreement with us, and we included this receivable amount within “Accounts, notes and interest receivable, net,” on our accompanying consolidated balance sheet.

Other Receivables and Payables

As of December 31, 2011 and December 31, 2010, our related party receivables (other than notes receivable discussed above in “—Notes Receivable”) totaled \$25.5 million and \$15.4 million, respectively. The December 31, 2011 receivables amount consisted of (i) \$14.6 million included within “Accounts, notes and interest receivable, net” on our accompanying consolidated balance sheet; and (ii) \$10.9 million of natural gas imbalance receivables included within “Other current assets.” The \$14.6 million receivable amount primarily consisted of amounts due from the Express pipeline system, NGPL, and KMI. The \$10.9 million natural gas imbalance receivable consisted of amounts due from both NGPL and the Rockies Express pipeline system.

The December 31, 2010 receivables amount consisted of (i) \$8.2 million included within “Accounts, notes and interest receivable, net” on our accompanying consolidated balance sheet; and (ii) \$7.2 million of natural gas imbalance receivables included within “Other current assets.” The \$8.2 million amount primarily related to accounts and interest receivables due from (i) the Express pipeline system; (ii) NGPL; and (iii) Plantation Pipe Line Company. Our related party natural gas imbalance receivables consisted of amounts due from NGPL.

As of December 31, 2011 and December 31, 2010, our related party payables totaled \$1.1 million and \$8.8 million, respectively. The December 31, 2011 related party payables primarily consisted of \$0.9 million amount included within “Accounts payable” and due to the noncontrolling partner of Globalplex Partners, a Louisiana joint venture owned 50% and controlled by us. The December 31, 2010 amount consisted of (i) \$5.1 million included within “Accounts payable” and primarily related to amounts due to KMI; and (ii) \$3.7 million of natural gas imbalance payables included within “Accrued other current liabilities” and consisting of amounts due to the Rockies Express pipeline system.

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a fiduciary duty to manage us in a manner beneficial to our unitholders. Our general partner owns all of KMR’s voting securities and elects all of KMR’s directors. KMI, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner, and the officers of KMI have fiduciary duties to manage KMI, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to the owners of KMI. Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us.

The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty. The partnership agreements also provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of KMI may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR’s board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand.

12. Commitments and Contingent Liabilities

Leases

The table below depicts future gross minimum rental commitments under our operating leases as of December 31, 2011 (in millions):

Year	Commitment
2012	\$ 51.6
2013	40.1
2014	31.0
2015	25.2
2016	20.4
Thereafter	64.5
Total minimum payments	<u>\$ 232.8</u>

The remaining terms on our operating leases, including probable elections to exercise renewal options, range from one to 37 years. Total lease and rental expenses for each of the years ended December 31, 2011, 2010 and 2009 were \$140.0 million, \$64.4 million and \$55.6 million, respectively. The increase in our lease and rental expenses in 2011 compared to 2010 was driven by a \$69.7 million increase in expense associated with adjustments to our Pacific operations' rights-of-way liabilities. For more information about this expense, see Note 16 "Litigation, Environmental and Other Contingencies—Commercial Litigation Matters—Union Pacific Railroad Company Easements." The amount of capital leases included within "Property, Plant and Equipment, net" in our accompanying consolidated balance sheets as of December 31, 2011 and 2010 are not material to our consolidated balance sheets.

Directors' Unit Appreciation Rights Plan

On April 1, 2003, KMR's compensation committee established our Directors' Unit Appreciation Rights Plan. Pursuant to this plan, and on this date of adoption, each of KMR's then three non-employee directors was granted 7,500 common unit appreciation rights. In addition, 10,000 common unit appreciation rights were granted to each of KMR's then three non-employee directors on January 21, 2004, at the first meeting of the board in 2004. During the first board meeting of 2005, the plan was terminated and replaced by the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors (discussed following); however, all unexercised awards made under the plan remain outstanding.

Upon the exercise of unit appreciation rights, we will pay, within thirty days of the exercise date, the participant an amount of cash equal to the excess, if any, of the aggregate fair market value of the unit appreciation rights exercised as of the exercise date over the aggregate award price of the rights exercised. The fair market value of one unit appreciation right as of the exercise date will be equal to the closing price of one common unit on the New York Stock Exchange on that date. The award price of one unit appreciation right will be equal to the closing price of one common unit on the New York Stock Exchange on the date of grant. Proceeds, if any, from the exercise of a unit appreciation right granted under the plan will be payable only in cash (that is, no exercise will result in the issuance of additional common units) and will be evidenced by a unit appreciation rights agreement. All unit appreciation rights granted vest on the six-month anniversary of the date of grant. If a unit appreciation right is not exercised in the ten year period following the date of grant, the unit appreciation right will expire and not be exercisable after the end of such period. In addition, if a participant ceases to serve on the board for any reason prior to the vesting date of a unit appreciation right, such unit appreciation right will immediately expire on the date of cessation of service and may not be exercised.

In 2009, Mr. Gaylord's estate exercised his 17,500 unit appreciation rights at an aggregate fair value of \$53.75 per unit, and it received a cash amount of \$179,275 (Mr. Edward O. Gaylord served as a KMR director until his death on September 28, 2008). As of December 31, 2010, 17,500 unit appreciation rights had been granted, vested and remained outstanding. All of these unit appreciation rights were owned by Mr. Waughtal. In 2011, Mr. Waughtal exercised his 17,500 unit appreciation rights at an aggregate fair value of \$81.86 per unit, and he received a cash amount of \$671,200. Accordingly, as of December 31, 2011, no unit appreciation rights remained outstanding.

Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors

On January 18, 2005, KMR's compensation committee established the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan. The plan is administered by KMR's compensation committee and KMR's board has sole discretion to terminate the plan at any time. The primary purpose of this plan is to promote our interests and the interests of our unitholders by aligning the compensation of the non-employee members of the board of directors of KMR with unitholders' interests. Further, since KMR's success is dependent on its operation and management of our business and our resulting performance, the plan is expected to align the compensation of the non-employee members of the board with the interests of KMR's shareholders.

The plan recognizes that the compensation to be paid to each non-employee director is fixed by the KMR board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving cash compensation, each non-employee director may elect to receive common units. Each election is made generally at or around the first board meeting in January of each calendar year and is effective for the entire calendar year. A non-employee director may make a new election each calendar year. The total number of common units authorized under this compensation plan is 100,000.

The elections under this plan for 2012, 2011 and 2010 were made effective January 17, 2012, January 18, 2011 and January 20, 2010, respectively. The elections for 2009 were made effective January 21, 2009 by Messrs. Hultquist and Waughtal, and January 28, 2009 by Mr. Lawrence.

Each annual election is evidenced by an agreement, the Common Unit Compensation Agreement, between us and each non-employee director, and this agreement contains the terms and conditions of each award. Pursuant to this agreement, all common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. Until the forfeiture restrictions lapse, common units issued under the plan may not be sold, assigned, transferred, exchanged, or pledged by a non-employee director. In the event the director's service as a director of KMR is terminated prior to the lapse of the forfeiture restriction either for cause, or voluntary resignation, each director will, for no consideration, forfeit to us all common units to the extent then subject to the forfeiture restrictions. Common units with respect to which forfeiture restrictions have lapsed cease to be subject to any forfeiture restrictions, and we will provide each director a certificate representing the units as to which the forfeiture restrictions have lapsed. In addition, each non-employee director has the right to receive distributions with respect to the common units awarded to him under the plan, to vote such common units and to enjoy all other unitholder rights, including during the period prior to the lapse of the forfeiture restrictions.

The number of common units to be issued to a non-employee director electing to receive the cash compensation in the form of common units will equal the amount of such cash compensation awarded, divided by the closing price of the common units on the New York Stock Exchange on the day the cash compensation is awarded (such price, the fair market value), rounded down to the nearest 50 common units. The common units will be issuable as specified in the Common Unit Compensation Agreement. A non-employee director electing to receive the cash compensation in the form of common units will receive cash equal to the difference between (i) the cash compensation awarded to such non-employee director and (ii) the number of common units to be issued to such non-employee director multiplied by the fair market value of a common unit. This cash payment is payable in four equal installments generally around March 31, June 30, September 30 and December 31 of the calendar year in which such cash compensation is awarded.

On January 21, 2009, each of KMR's three non-employee directors (with Mr. Lawrence replacing Mr. Gaylord after Mr. Gaylord's death) was awarded cash compensation of \$160,000 for board service during 2009. Effective January 21, 2009, Mr. Hultquist and Mr. Waughtal elected to receive the full amount of their compensation in the form of cash only. Effective January 28, 2009, Mr. Lawrence elected to receive compensation of \$159,136 in the form of our common units and was issued 3,200 common units. His remaining compensation (\$864) was paid in cash as described above. No other compensation was paid to the non-employee directors during 2009.

On January 20, 2010, each of KMR's three non-employee directors was awarded cash compensation of \$160,000 for board service during 2010. Effective January 20, 2010, Mr. Hultquist and Mr. Waughtal elected to receive the full amount of their compensation in the form of cash only. Mr. Lawrence elected to receive compensation of \$159,495 in the form of our common units and was issued 2,450 common units. His remaining compensation (\$505) was paid in cash as described above. No other compensation was paid to the non-employee directors during 2010.

On January 18, 2011, each of KMR's then three non-employee directors was awarded cash compensation of \$180,000 for board service during 2011. Effective January 18, 2011, Mr. Hultquist and Mr. Waughtal elected to receive the full amount of their compensation in the form of cash only. Mr. Lawrence elected to receive compensation of \$176,964 in the form of our common units and was issued 2,450 common units. On July 20, 2011, Mr. Lawrence resigned from the KMR and Kinder Morgan G.P., Inc. boards of directors and was replaced by Mr. Ted A. Gardner. Mr. Lawrence received remaining compensation of \$1,518 paid in cash during the first half of 2011 (amount equal to one-half of the difference between (i) his total cash compensation award and (ii) the value of cash compensation received in the form of our common units according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors). Mr. Gardner was awarded cash compensation of \$90,000 for board service during 2011, and his compensation was paid in cash as described above. No other compensation was paid to the non-employee directors during 2011.

On January 17, 2012, each of KMR's three non-employee directors was awarded cash compensation of \$180,000 for board service during 2012. Each of the non-employee directors elected to receive the full amount of their compensation in the form of cash only. No other compensation will be paid to the non-employee directors during 2012.

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, 2011, our contingent debt obligations, as well as our obligations with respect to related letters of credit, consisted of the following two items:

<u>Entity</u>	<u>Our Ownership Interest</u>	<u>Investment Type</u>	<u>Total Entity Debt</u>	<u>Our Contingent Share of Entity Debt (a)</u>
Cortez Pipeline Company(b)	50%	General Partner	\$ 138.5(c)	\$ 80.0(d)
Nassau County, Florida Ocean Highway and Port Authority(e)	N/A	N/A	N/A	\$ 16.7(f)

- (a) Represents the portion of the entity's debt that we may be responsible for if the entity cannot satisfy its obligations.
- (b) Cortez Pipeline Company is a Texas general partnership that owns and operates a common carrier carbon dioxide pipeline system. The remaining general partner interests are owned by ExxonMobil Cortez Pipeline, Inc., an indirect wholly-owned subsidiary of Exxon Mobil Corporation, and Cortez Vickers Pipeline Company, an indirect subsidiary of M.E. Zuckerman Energy Investors Incorporated.
- (c) Amount consists of (i) \$21.4 million aggregate principal amount of Series D notes due May 15, 2013 (interest on the Series D notes is paid annually and based on a fixed interest rate of 7.14% per annum); (ii) \$100.0 million of variable rate Series E notes due December 11, 2012 (interest on the Series E notes is paid quarterly and based on an interest rate of three-month LIBOR plus a spread); and (iii) \$17.1 million of outstanding borrowings under a \$40.0 million committed revolving bank credit facility that is also due December 11, 2012.
- (d) We are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt (\$69.3 million). In addition, as of December 31, 2011, Shell Oil Company shares our several guaranty obligations jointly and severally for \$21.4 million of Cortez's debt balance related to the Series D notes; however, we are obligated to indemnify Shell for the liabilities it incurs in connection with such guaranty. Accordingly, as of December 31, 2011, we have a letter of credit in the amount of \$10.7 million issued by JP Morgan Chase, in order to secure our indemnification obligations to Shell for 50% of the Cortez debt balance of \$21.4 million related to the Series D notes.
- Further, pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company are required to contribute capital to Cortez in the event of a cash deficiency. The agreement contractually supports the financings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline to fund cash deficiencies at Cortez Pipeline, including anticipated deficiencies and cash deficiencies relating to the repayment of principal and interest on the debt of Cortez Capital Corporation. The partners' respective parent or other companies further severally guarantee the obligations of the Cortez Pipeline owners under this agreement.
- (e) Arose from our Vopak terminal acquisition in July 2001. Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the state of Florida.
- (f) We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year, and corresponding reductions are made to the letter of credit. As of December 31, 2011, this letter of credit had a face amount of \$16.7 million.

On February 25, 2011, Midcontinent Express Pipeline LLC entered into a three-year \$75.0 million unsecured revolving bank credit facility that is due February 25, 2014. This credit facility replaced Midcontinent Express' previous \$175.4 million credit facility that was terminated on February 28, 2011, and on this same date, each of its two member owners, including us, were released from their respective debt obligations under the previous guaranty agreements. Accordingly, we no longer have a contingent debt obligation with respect to Midcontinent Express Pipeline LLC.

On July 28, 2011, Fayetteville Express Pipeline LLC entered into (i) a new unsecured \$600.0 million term loan that is due on July 28, 2012, with the ability to extend one additional year; and (ii) a \$50.0 million unsecured revolving bank credit facility that is due on July 28, 2015. These debt instruments replaced Fayetteville Express' \$1.1 billion credit facility that was terminated on July 28, 2011, and on this same date, each of its two member owners, including us, were released from their respective debt obligations under the previous guaranty agreements. Accordingly, we no longer have a contingent debt obligation with respect to Fayetteville Express Pipeline LLC.

For additional information regarding our debt facilities see Note 8 "Debt."

13. Risk Management

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

Energy Commodity Price Risk Management

We are exposed to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil as a result of the forecasted purchase or sale of these products. Specifically, these risks are primarily associated with price volatility related to (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales; (ii) natural gas purchases; and (iii) natural gas system use and storage. Price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations.

Our principal use of energy commodity derivative contracts is to mitigate the risk associated with unfavorable market movements in the price of energy commodities. Our energy commodity derivative contracts act as a hedging (offset) mechanism against the volatility of energy commodity prices by allowing us to transfer this price risk to counterparties who are able and willing to bear it.

For derivative contracts that are designated and qualify as cash flow hedges pursuant to U.S. generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective (as defined by U.S. generally accepted accounting principles) in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in "revenues" when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion as defined by U.S. generally accepted accounting principles), is recognized in earnings during the current period. The effectiveness of hedges using an option contract may be assessed based on changes in the option's intrinsic value with the change in the time value of the contract being excluded from the assessment of hedge effectiveness. Changes in the excluded component of the change in an option's time value are included currently in earnings. During each of the years ended December 31, 2011 and 2010, we reclassified losses of \$255.3 million and \$188.4 million, respectively, from "Accumulated other comprehensive income (loss)" into earnings. No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, the amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred). The proceeds or payments resulting from the settlement of our cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

The "Accumulated other comprehensive income" balance included in our Partners' Capital (exclusive of the portion included in "Noncontrolling interests") was \$3.3 million as of December 31, 2011. As of December 31, 2010, we had an "Accumulated other comprehensive loss" balance of \$186.4 million. These totals included accumulated loss amounts of \$40.9 million and \$307.1 million, respectively, associated with energy commodity price risk management activities. We expect to reclassify an approximate \$45.0 million loss amount associated with energy commodity price risk management activities and included in our Partners' Capital as of December 31, 2011 into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices. As of December 31, 2011, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2015.

As of December 31, 2011, we had entered into 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.....	(20.9) million barrels
Natural gas fixed price	(11.4) billion cubic feet
Natural gas basis	(11.4) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas basis	13.5 billion cubic feet

For derivative contracts that are not designated as a hedge for accounting purposes, all realized and unrealized gains and losses are recognized in the statement of income during the current period. These types of transactions include basis spreads, basis-only positions and gas daily swap positions. We primarily enter into these positions to economically hedge an exposure through a relationship that does not qualify for hedge accounting. Until settlement occurs, this will result in non-cash gains or losses being reported in our operating results.

Interest Rate Risk Management

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. We use interest rate swap agreements to manage the interest rate risk associated with the fair value of our fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

Since the fair value of fixed rate debt varies inversely with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest in order to convert the interest expense associated with certain of our senior notes from fixed rates to variable rates, resulting in future cash flows that vary with the market rate of interest. These swaps, therefore, hedge against changes in the fair value of our fixed rate debt that result from market interest rate changes. For derivative contracts that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings.

As of December 31, 2011, we had a combined notional principal amount of \$5,325 million of fixed-to-variable interest rate swap agreements. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of December 31, 2011, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

As of December 31, 2010, we had a combined notional principal amount of \$4,775 million of fixed-to-variable interest rate swap agreements, effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. In March 2011, we entered into four additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of \$500 million, effectively converting the interest expense associated with our 3.50% senior notes due March 1, 2016 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread. In August 2011, we (i) entered into two additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of \$250 million, effectively converting a portion of the interest expense associated with our 4.15% senior notes due March 1, 2022 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread; and (ii) terminated two existing fixed-to-variable swap agreements having a combined notional principal amount of \$200 million in two separate transactions. We received combined proceeds of \$73.0 million from the early termination of these two swap agreements.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" on our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of December 31, 2011 and 2010 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		December 31, 2011	December 31, 2010	December 31, 2011	December 31, 2010
	Balance sheet location	Fair value	Fair value	Fair value	Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current	\$ 65.3	\$ 20.1	\$ (116.3)	\$ (275.9)
	Non-current	39.4	43.1	(38.5)	(103.0)
Subtotal		104.7	63.2	(154.8)	(378.9)
Interest rate swap agreements	Current	3.0	-	-	-
	Non-current	592.5	217.6	-	(69.2)
Subtotal		595.5	217.6	-	(69.2)
Total		700.2	280.8	(154.8)	(448.1)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current	3.1	3.9	(4.5)	(5.6)
	Non-current	0.1	-	(0.2)	-
Total		3.2	3.9	(4.7)	(5.6)
Total derivatives		<u>\$ 703.4</u>	<u>\$ 284.7</u>	<u>\$ (159.5)</u>	<u>\$ (453.7)</u>

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within “Value of interest rate swaps” on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of December 31, 2011 and 2010, this unamortized premium totaled \$483.4 million and \$456.5 million, respectively, and as of December 31, 2011, the weighted average amortization period for this premium was approximately 17.8 years.

Effect of Derivative Contracts on the Income Statement

The following three tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the years ended December 31, 2011 and 2010 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a)		Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged items(a)	
		Year Ended December 31,				Year Ended December 31,	
		2011	2010			2011	2010
Interest rate swap agreements	Interest, net – income/(expense)	\$ 520.1	\$ 302.0	Fixed rate debt	Interest, net – income/(expense)	\$ (520.1)	\$ (302.0)
Total		<u>\$ 520.1</u>	<u>\$ 302.0</u>	Total		<u>\$ (520.1)</u>	<u>\$ (302.0)</u>

(a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt which exactly offset each other as a result of no hedge ineffectiveness.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of 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,	
	2011	2010		2011	2010		2011	2010
Energy commodity derivative contracts	\$ 14.1	\$ (76.1)	Revenues-natural gas sales	\$ 3.3	\$ 8.2	Revenues-natural gas sales	\$ -	\$ -
			Revenues-product sales and other	(269.3)	(211.3)	Revenues-product sales and other	5.2	5.3
			Gas purchases and other costs of sales	10.7	14.7	Gas purchases and other costs of sales	-	-
Total	\$ 14.1	\$ (76.1)	Total	\$ (255.3)	\$ (188.4)	Total	\$ 5.2	\$ 5.3

Derivatives not designated as hedging contracts	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative	
		Year Ended December 31, 2011	Year Ended December 31, 2010
Energy commodity derivative contracts	Gas purchases and other costs of sales	\$ (0.2)	\$ 2.3
Total		<u>\$ (0.2)</u>	<u>\$ 2.3</u>

Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our over-the-counter swaps and options are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

The maximum potential exposure to credit losses on our derivative contracts as of December 31, 2011 was (in millions):

	Asset position
Interest rate swap agreements.....	\$ 595.5
Energy commodity derivative contracts	107.9
Gross exposure	703.4
Netting agreement impact.....	(62.4)
Net exposure.....	<u>\$ 641.0</u>

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, 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, 2011 and 2010, we had no outstanding letters of credit supporting our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil.

As of December 31, 2011 and 2010, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling \$10.1 million and \$2.4 million, respectively, and we reported these amounts within “Accrued other current liabilities” in our accompanying consolidated balance sheets.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. Based on contractual provisions as of December 31, 2011, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

Credit ratings downgraded (a)	Incremental obligations	Cumulative obligations(b)
One notch to BBB-/Baa3	\$ -	\$ -
Two notches to below BBB-/Baa3 (below investment grade) ...	\$ 32.3	\$ 32.3

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a two notch downgrade to below BBB-/Baa3 by one agency would not trigger the entire \$32.3 million incremental obligation.

(b) Includes current posting at current rating.

14. Fair Value

The Codification emphasizes that fair value is a market-based measurement that should be determined based on assumptions (inputs) that market participants would use in pricing an asset or liability. Inputs may be observable or unobservable, and valuation techniques used to measure fair value should maximize the use of relevant observable inputs and minimize the use of unobservable inputs. Accordingly, the Codification establishes a hierarchal disclosure framework that ranks the quality and reliability of information used to determine fair values. The hierarchy is associated with the level of pricing observability utilized in measuring fair value and defines three levels of inputs to the fair value measurement process—quoted prices are the most reliable valuation inputs, whereas model values that include inputs based on unobservable data are the least reliable. 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; and (ii) interest rate swap agreements as of December 31, 2011 and 2010, based on the three levels established by the Codification (in millions). The fair value measurements in the tables below do not include cash margin deposits made by us or our counterparties, which would be reported within “Restricted deposits” and “Accrued other current liabilities,” respectively, in our accompanying consolidated balance sheets.

Asset fair value measurements using				
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	Total			
As of December 31, 2011				
Energy commodity derivative contracts(a)	\$ 107.9	\$ 34.1	\$ 47.0	\$ 26.8
Interest rate swap agreements	\$ 595.5	\$ -	\$ 595.5	\$ -
As of December 31, 2010				
Energy commodity derivative contracts(a)	\$ 67.1	\$ -	\$ 23.5	\$ 43.6
Interest rate swap agreements	\$ 217.6	\$ -	\$ 217.6	\$ -

Liability fair value measurements using				
		Quoted prices in active markets for identical liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	Total			
As of December 31, 2011				
Energy commodity derivative contracts(a)	\$ (159.5)	\$ (14.5)	\$ (124.9)	\$ (20.1)
Interest rate swap agreements	\$ -	\$ -	\$ -	\$ -
As of December 31, 2010				
Energy commodity derivative contracts(a)	\$ (384.5)	\$ -	\$ (359.7)	\$ (24.8)
Interest rate swap agreements	\$ (69.2)	\$ -	\$ (69.2)	\$ -

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of natural gas basis swaps and West Texas Intermediate options.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the years ended December 31, 2011 and 2010 (in millions):

Significant unobservable inputs (Level 3)

	Year Ended December 31,	
	2011	2010
Derivatives-net asset (liability)		
Beginning of period	\$ 18.8	\$ 13.0
Transfers into Level 3	-	-
Transfers out of Level 3	-	-
Total gains or (losses):		
Included in earnings	(2.3)	(1.2)
Included in other comprehensive income	(11.4)	2.9
Purchases	4.6	-
Issuances	-	-
Sales	-	-
Settlements	(3.0)	4.1
End of period	<u>\$ 6.7</u>	<u>\$ 18.8</u>

The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date..... \$ (1.7) \$ (4.2)

Fair Value of Financial Instruments

Fair value as used in the disclosure of financial instruments represents the amount at which an instrument could be exchanged in a current transaction between willing parties. As of each reporting date, the estimated fair value of our outstanding publicly-traded debt is based upon quoted market prices, if available, and for all other debt, fair value is based upon prevailing interest rates currently available to us. In addition, we adjust (discount) the fair value measurement of our long-term debt for the effect of credit risk.

The estimated fair value of our outstanding debt balance as of December 31, 2011 and 2010 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	December 31, 2011		December 31, 2010	
	Carrying Value	Estimated fair value	Carrying Value	Estimated fair value
Total debt.....	\$ 12,797.3	\$ 14,237.5	\$ 11,539.8	\$ 12,443.4

15. Reportable Segments

We divide our operations into five reportable business segments. These segments and their principal source of revenues are as follows:

- Products Pipelines—the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids;
- Natural Gas Pipelines—the sale, transport, processing, treating, storage and gathering of natural gas;
- CO₂—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;
- Terminals—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals; and
- Kinder Morgan Canada—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States.

We evaluate performance principally based on each segment's earnings before depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income, and unallocable 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 maker organizes their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

Financial information by segment follows (in millions):

	Year Ended December 31,		
	2011	2010	2009
Revenues			
Products Pipelines			
Revenues from external customers	\$ 914.0	\$ 883.0	\$ 826.6
Intersegment revenues	-	-	-
Natural Gas Pipelines			
Revenues from external customers	4,265.1	4,416.5	3,806.9
Intersegment revenues	-	-	-
CO ₂			
Revenues from external customers	1,416.2	1,245.7	1,035.7
Intersegment revenues	-	-	-
Terminals			
Revenues from external customers	1,313.5	1,264.0	1,108.1
Intersegment revenues	1.1	1.1	0.9
Kinder Morgan Canada			
Revenues from external customers	302.4	268.5	226.1
Intersegment revenues	-	-	-
Total segment revenues	8,212.3	8,078.8	7,004.3
Less: Total intersegment revenues	(1.1)	(1.1)	(0.9)
Total consolidated revenues	<u>\$ 8,211.2</u>	<u>\$ 8,077.7</u>	<u>\$ 7,003.4</u>
Operating expenses(a)			
Products Pipelines	\$ 499.7	\$ 414.6	\$ 269.5
Natural Gas Pipelines	3,551.6	3,750.3	3,193.0
CO ₂	342.5	308.1	271.1
Terminals	634.0	629.2	536.8
Kinder Morgan Canada	97.7	91.6	72.5
Total segment operating expenses	5,125.5	5,193.8	4,342.9
Less: Total intersegment operating expenses	(1.1)	(1.1)	(0.9)
Total consolidated operating expenses	<u>\$ 5,124.4</u>	<u>\$ 5,192.7</u>	<u>\$ 4,342.0</u>
Other expense (income)			
Products Pipelines	\$ (10.0)	\$ 4.2	\$ 0.6
Natural Gas Pipelines	-	-	(7.8)
CO ₂	-	-	-
Terminals	(0.9)	(4.3)	(27.6)
Kinder Morgan Canada	-	-	-
Total consolidated Other expense (income)	<u>\$ (10.9)</u>	<u>\$ (0.1)</u>	<u>\$ (34.8)</u>
Depreciation, depletion and amortization			
Products Pipelines	\$ 105.2	\$ 100.7	\$ 94.1
Natural Gas Pipelines	161.4	124.2	93.4
CO ₂	437.2	452.9	487.9
Terminals	195.0	184.1	136.9
Kinder Morgan Canada	55.7	42.9	38.5
Total consol. depreciation, depletion and amortization	<u>\$ 954.5</u>	<u>\$ 904.8</u>	<u>\$ 850.8</u>
Earnings from equity investments			
Products Pipelines	\$ 50.6	\$ 33.1	\$ 29.0
Natural Gas Pipelines	227.2	169.1	141.8
CO ₂	24.1	22.5	22.3
Terminals	11.2	1.7	0.7
Kinder Morgan Canada	(2.0)	(3.3)	(4.1)
Total consolidated equity earnings	<u>\$ 311.1</u>	<u>\$ 223.1</u>	<u>\$ 189.7</u>

Amortization of excess cost of equity investments			
Products Pipelines	\$ 3.7	\$ 3.4	\$ 3.4
Natural Gas Pipelines	1.0	0.4	0.4
CO ₂	2.0	2.0	2.0
Terminals	-	-	-
Kinder Morgan Canada	-	-	-
Total consol. amortization of excess cost of equity investments	<u>\$ 6.7</u>	<u>\$ 5.8</u>	<u>\$ 5.8</u>
Interest income			
Products Pipelines	\$ 3.1	\$ 4.0	\$ 4.1
Natural Gas Pipelines	2.2	2.3	6.2
CO ₂	0.8	2.0	-
Terminals	0.1	-	-
Kinder Morgan Canada	13.8	13.2	12.0
Total segment interest income	<u>20.0</u>	<u>21.5</u>	<u>22.3</u>
Unallocated interest income	2.9	1.2	0.2
Total consolidated interest income	<u>\$ 22.9</u>	<u>\$ 22.7</u>	<u>\$ 22.5</u>
Other, net-income (expense)			
Products Pipelines	\$ 5.1	\$ 12.4	\$ 8.3
Natural Gas Pipelines(b)	(164.6)	2.0	25.6
CO ₂	4.4	2.5	-
Terminals	5.4	4.7	3.7
Kinder Morgan Canada	-	2.6	11.9
Total consolidated other, net-income (expense)	<u>\$ (149.7)</u>	<u>\$ 24.2</u>	<u>\$ 49.5</u>
Income tax (expense) benefit			
Products Pipelines	\$ (20.0)	\$ (9.2)	\$ (13.4)
Natural Gas Pipelines	(4.1)	(3.3)	(5.7)
CO ₂	(4.4)	0.9	(4.0)
Terminals	6.3	(5.3)	(5.2)
Kinder Morgan Canada	(14.9)	(7.8)	(18.9)
Total segment income tax benefit (expense)	<u>(37.1)</u>	<u>(24.7)</u>	<u>(47.2)</u>
Unallocated income tax benefit (expense).....	(8.7)	(9.9)	(8.5)
Total consolidated income tax benefit (expense).....	<u>\$ (45.8)</u>	<u>\$ (34.6)</u>	<u>\$ (55.7)</u>
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(c)			
Products Pipelines	\$ 463.1	\$ 504.5	\$ 584.5
Natural Gas Pipelines	774.2	836.3	789.6
CO ₂	1,098.6	965.5	782.9
Terminals	704.5	641.3	599.0
Kinder Morgan Canada	201.6	181.6	154.5
Total segment earnings before DD&A	<u>3,242.0</u>	<u>3,129.2</u>	<u>2,910.5</u>
Total segment depreciation, depletion and amortization	<u>(954.5)</u>	<u>(904.8)</u>	<u>(850.8)</u>
Total segment amortization of excess cost of equity investments. .	(6.7)	(5.8)	(5.8)
General and administrative expenses	(472.7)	(375.2)	(330.3)
Interest expense, net of unallocable interest income	(531.0)	(506.4)	(431.3)
Unallocable income tax expense	(8.7)	(9.9)	(8.5)
Total consolidated net income	<u>\$ 1,268.4</u>	<u>\$ 1,327.1</u>	<u>\$ 1,283.8</u>
Capital expenditures(d)			
Products Pipelines	\$ 253.8	\$ 144.2	\$ 199.8
Natural Gas Pipelines	152.8	135.4	372.0
CO ₂	432.5	372.8	341.8
Terminals	332.7	326.3	378.2
Kinder Morgan Canada	27.7	22.2	32.0
Total consolidated capital expenditures.....	<u>\$ 1,199.5</u>	<u>\$ 1,000.9</u>	<u>\$ 1,323.8</u>

Investments at December 31

Products Pipelines	\$ 218.5	\$ 215.6	\$ 203.7
Natural Gas Pipelines	2,887.0	3,563.3	2,542.9
CO ₂	10.4	9.9	11.2
Terminals	164.0	27.4	18.7
Kinder Morgan Canada	66.3	69.8	68.7
Total consolidated investments.....	<u>\$ 3,346.2</u>	<u>\$ 3,886.0</u>	<u>\$ 2,845.2</u>

Assets at December 31

Products Pipelines	\$ 4,479.3	\$ 4,369.1	\$ 4,299.0
Natural Gas Pipelines	9,957.5	8,809.7	7,772.7
CO ₂	2,147.3	2,141.2	2,224.5
Terminals	4,428.3	4,138.6	3,636.6
Kinder Morgan Canada	1,826.7	1,870.0	1,797.7
Total segment assets	22,839.1	21,328.6	19,730.5
Corporate assets(e)	1,263.6	532.5	531.7
Total consolidated assets	<u>\$ 24,102.7</u>	<u>\$ 21,861.1</u>	<u>\$ 20,262.2</u>

- (a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
- (b) 2011 amount includes a \$167.2 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value (discussed further in Note 3).
- (c) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).
- (d) Sustaining capital expenditures, including our share of the sustaining capital expenditures of the following seven joint ventures: Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, Fayetteville Express Pipeline LLC, Cypress Interstate Pipeline LLC, EagleHawk Field Services LLC, for 2011 only, Red Cedar Gathering Company, and until July 1, 2011, KinderHawk Field Services LLC totaled \$212.1 million in 2011, \$179.2 million in 2010 and \$172.2 million in 2009. Sustaining capital expenditures are defined as capital expenditures which do not increase the capacity of an asset.
- (e) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to the fair value of interest rate swaps.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2011, 2010 and 2009, we reported total consolidated interest expense of \$533.9 million, \$507.6 million and \$431.5 million, respectively.

Our total operating revenues are derived from a wide customer base. For each of the years ended December 31, 2011, 2010 and 2009, no revenues from transactions with a single external customer amounted to 10% or more of our total consolidated revenues.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	Year Ended December 31,		
	2011	2010	2009
Revenues from external customers			
United States	\$ 7,781.2	\$ 7,701.7	\$ 6,680.5
Canada	411.5	356.5	301.9
Mexico and other(a).....	18.5	19.5	21.0
Total consolidated revenues from external customers.....	<u>\$ 8,211.2</u>	<u>\$ 8,077.7</u>	<u>\$ 7,003.4</u>

Long-lived assets at December 31(b)	2011	2010	2009
United States	\$ 17,858.5	\$ 16,929.5	\$ 15,556.6
Canada	1,843.4	1,908.5	1,813.6
Mexico and other(a)	76.0	86.4	89.1
Total consolidated long-lived assets.....	<u>\$ 19,777.9</u>	<u>\$ 18,924.4</u>	<u>\$ 17,459.3</u>

(a) Includes operations in Mexico and until August 31, 2011, the Netherlands.

(b) Long-lived assets exclude (i) goodwill; (ii) other intangibles, net; and (iii) long-term note receivables from related parties.

16. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during 2011. This note also contains a description of any material legal proceedings that were initiated against us during 2011, and a description of any material events occurring subsequent to December 31, 2011 but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calneve Pipe Line LLC as Calneve; Chevron Products Company as Chevron; BP West Coast Products, LLC as BP; ConocoPhillips Company as ConocoPhillips; Tesoro Refining and Marketing Company as Tesoro; Western Refining Company, L.P. as Western Refining; Navajo Refining Company, L.L.C. as Navajo; Holly Refining & Marketing Company LLC as Holly; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Kinder Morgan CO₂ Company, L.P. (the successor to Shell CO₂ Company, Ltd.) as Kinder Morgan CO₂; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the American Railway Engineering and Maintenance-of-Way Association as AREMA; the Texas Commission of Environmental Quality as the TCEQ; The Premcor Refining Group, Inc. as Premcor; Port Arthur Coker Company as PACC; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; the federal Comprehensive Environmental Response, Compensation and Liability Act as CERCLA; the United States Environmental Protection Agency as the U.S. EPA; the United States Environmental Protection Agency's Suspension and Debarment Division as the U.S. EPA SDD; the New Jersey Department of Environmental Protection as the NJDEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Liquids Terminals LLC as KMLT; our subsidiary Kinder Morgan Interstate Gas Transmission LLC as KMIGT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. "OR" dockets designate complaint proceedings, and "IS" dockets designate protest proceedings.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP and Calneve are subject to a number of ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. In general, these complaints and protests allege the rates and tariffs charged by SFPP and Calneve are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaints) or refunds of any excess rates paid, and SFPP and/or Calneve may be required to reduce their 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: (i) whether certain of our rates are "grandfathered" under the Energy Policy Act of 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases are justified; and (iv) the appropriate level of return and income tax allowance we may include in our rates.

SFPP

The following FERC dockets are currently pending:

- FERC Docket No. IS08-390 (West Line Rates) (Opinion Nos. 511 and 511-A)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Status: FERC order issued on December 16, 2011. While the order made certain findings that were adverse to SFPP, it ruled in favor of SFPP on many significant issues. SFPP made a compliance filing at the end of January 2012. However, SFPP also filed a rehearing request on certain adverse rulings in the FERC order. It is not possible to predict the outcome of the FERC review of the rehearing request or appellate review of this order;
- FERC Docket No. IS09-437 (East Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, Western Refining, Navajo, Holly, and Southwest Airlines—Status: Initial decision issued on February 10, 2011. A FERC administrative law judge generally made findings adverse to SFPP, found that East Line rates should have been lower, and recommended that SFPP pay refunds for alleged over-collections. SFPP has filed a brief with the FERC taking exception to these and other portions of the initial decision. The FERC will review the initial decision, and while the initial decision is inconsistent with a number of the issues ruled on in FERC's Opinion Nos. 511 and 511-A, it is not possible to predict the outcome of FERC or appellate review;
- FERC Docket No. IS11-444 (2011 Index Rate Increases)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines, Tesoro, Western Refining, Navajo, and Holly—Status: SFPP withdrew all index rate increases except those that pertain to the West Line. As to the West Line, the index rate increases are currently accepted and suspended, subject to refund, and the case is before a FERC hearing judge. SFPP filed direct testimony in December 2011 and Supplemental Direct testimony in January 2012;
- FERC Docket No. OR11-13 (SFPP Base Rates)—Complainant: ConocoPhillips—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. ConocoPhillips permitted to amend its complaint based on additional data;
- FERC Docket No. OR11-16 (SFPP Indexed Rates)—Complainant: Chevron—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Chevron permitted to amend its complaint based on additional data;
- FERC Docket No. OR11-18 (SFPP Base Rates)—Complainant: Tesoro—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. Tesoro permitted to amend its complaint based on additional data;
- FERC Docket No. OR12-1 (SFPP Index Ceiling Levels)—Complainant: Chevron—Status: Complaint was filed October 5, 2011. SFPP answered on October 26, 2011. Matter is currently pending before the FERC;
- FERC Docket No. OR12-2 (SFPP Index Ceiling Levels)—Complainant: Tesoro—Status: Complaint was filed October 5, 2011. SFPP answered on October 26, 2011. Matter is currently pending before the FERC; and
- FERC Docket No. OR12-3 (SFPP Index Ceiling Levels)—Complainant: ConocoPhillips—Status: Complaint was filed October 5, 2011. SFPP answered on October 26, 2011. Matter is currently pending before the FERC.

With respect to the SFPP proceedings above and the Calnev proceedings discussed below, we estimate that the shippers are seeking approximately \$30.0 million in annual rate reductions and approximately \$150.0 million in refunds. However, applying the principles of Opinion Nos. 511 and 511-A, a full FERC decision on our West Line rates, to these cases would result in substantially lower rate reductions and refunds. We do not expect refunds in these cases to have an impact on our distributions to our limited partners.

Calnev

On March 17, 2011, the FERC issued an order consolidating the following proceedings and setting them for hearing. The FERC further held the hearing proceedings in abeyance to allow for settlement judge proceedings:

- FERC Docket Nos. OR07-7, OR07-18, OR07-19, OR07-22, OR09-15, and OR09-20 (consolidated) (Calnev Rates)—Complainants: Tesoro, Airlines, BP, Chevron, ConocoPhillips and Valero Marketing—Status: Before a FERC settlement judge.

Trailblazer Pipeline Company LLC

On July 7, 2010, our subsidiary Trailblazer Pipeline Company LLC refunded a total of approximately \$0.7 million to natural gas shippers covering the period January 1, 2010 through May 31, 2010 as part of a settlement reached with shippers to eliminate the December 1, 2009 rate filing obligation contained in its Docket No. RP03-162 rate case settlement. As part of the agreement with shippers, Trailblazer commenced billing reduced tariff rates as of June 1, 2010 with an additional reduction in tariff rates that took effect January 1, 2011.

Kinder Morgan Interstate Gas Transmission LLC Section 5 Proceeding

On November 18, 2010, our subsidiary KMIGT was notified by the FERC of a proceeding against it pursuant to Section 5 of the Natural Gas Act. The proceeding set for hearing a determination of whether KMIGT's current rates, which were approved by the FERC in KMIGT's last transportation rate case settlement, remain just and reasonable. The FERC made no findings in its order as to what would constitute just and reasonable rates or a reasonable return for KMIGT. A proceeding under Section 5 of the Natural Gas Act is prospective in nature and any potential change in rates charged customers by KMIGT can only occur after the FERC has issued a final order. Prior to that, an administrative law judge presides over an evidentiary hearing and makes an initial decision (which the FERC has directed to be issued within 47 weeks).

On March 23, 2011, the Chief Judge suspended the procedural schedule in this proceeding because all parties reached a settlement in principle that will resolve all issues set for hearing. On May 5, 2011, KMIGT filed a formal settlement document, referred to in this Note as the Settlement and which is supported or not opposed by all parties of record, and on September 22, 2011, the FERC approved the Settlement.

The Settlement resolves all issues in the proceeding and provides shippers on KMIGT's system with prospective reductions in the fuel and gas and lost and unaccounted for rates, referred to as the Fuel Retention Factors, effective June 1, 2011. The Settlement results in a 27% reduction in the Fuel Retention Factors billed to shippers effective June 1, 2011, as compared to the Fuel Retention Factors approved and in effect on March 1, 2011. The Settlement also provides for a second stepped reduction, resulting in a total 30% reduction in the Fuel Retention Factors billed to shippers and effective January 1, 2012, for certain segments of the former Pony Express pipeline system. Except for these reductions to the Fuel Retention Factors, other transportation and storage rates will not be altered by the Settlement.

California Public Utilities Commission Proceedings

We have previously reported ratemaking and complaint proceedings against SFPP pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services. These matters have been consolidated and assigned to two administrative law judges.

On April 6, 2010, a CPUC administrative law judge issued a proposed decision in several intrastate rate cases involving SFPP and a number of its shippers. The proposed decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance and allocation of environmental expenses, which we believe are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. Moreover, the proposed decision orders refunds relating to these issues where the underlying rates were previously deemed reasonable by the CPUC, which we believe to be contrary to California law. SFPP filed comments on May 3, 2010 outlining what it believes to be the errors in law and fact within the proposed decision, and on May 5, 2010, SFPP made oral arguments before the full CPUC. On November 12, 2010, an alternate proposed decision was issued.

On May 26, 2011, the CPUC issued an order adopting the proposed decision, which would eliminate from SFPP's transportation rates an allowance for income taxes on income generated by SFPP. The order also calls for partial refund of rates charged to shippers that were previously deemed reasonable by the CPUC. The order would only affect rates for SFPP's intrastate pipeline service within the state of California and would have no effect on SFPP's interstate rates, which do include such an allowance under orders of the FERC and opinions of the U.S. Court of Appeals for the District of Columbia. SFPP has filed a request for rehearing by the CPUC of the May 26, 2011 order, which remains pending before the CPUC.

On June 22, 2011, a CPUC administrative law judge issued a proposed decision substantially reducing SFPP's authorized cost of service, requiring SFPP's prospective rates to be reduced to reflect the authorized cost of service, and ordering SFPP to pay refunds from May 24, 2007 to the present of revenues collected in excess of the authorized cost of service. SFPP filed comments on the proposed decision on June 22, 2011, outlining what it believes to be errors in law and fact in the proposed decision, including the requirement that refunds be made from May 24, 2007. By subsequent ruling of the administrative law judge, the referenced proposed decision has been withdrawn. The ruling indicated that a revised proposed decision would be issued at an unspecified date, subject to comments from the parties and a request for oral argument before the full CPUC.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately \$375.0 million in reparation payments and approximately \$30.0 million in annual rate reductions. The actual amount of reparations will be determined through further proceedings at the CPUC and we believe that the appropriate application of the May 26, 2011 CPUC order and the June 22, 2011 administrative law decision will result in a considerably lower amount. In addition, further procedural steps, including motions for rehearing and writ of review to California's Court of Appeals, will be taken with respect to these decisions. We do not expect any reparations that we would pay in these matters to have an impact on our distributions to our limited partners.

In September 2011, with respect to certain cases, we made refund payments of \$18.4 million to various intrastate shippers pursuant to orders received from the CPUC.

Carbon Dioxide Litigation

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to our subsidiary Kinder Morgan CO₂. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO₂ with respect to carbon dioxide produced from the McElmo Dome unit for tax years 2005, 2006, and 2007. The total amount of tax assessed was \$5.7 million, plus interest of \$1.0 million, plus penalties of \$1.7 million. Kinder Morgan CO₂ protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO₂ is now awaiting the Colorado Department of Revenue's response to the protest.

Montezuma County, Colorado Property Tax Assessment

In November of 2009, the County Treasurer of Montezuma County, Colorado, issued to Kinder Morgan CO₂, as operator of the McElmo Dome unit, retroactive tax bills for tax year 2008, in the amount of \$2 million. Of this amount, 37.2% is attributable to Kinder Morgan CO₂'s interest. The retroactive tax bills were based on the assertion that a portion of the actual value of the carbon dioxide produced from the McElmo Dome unit was omitted from the 2008 tax roll due to an alleged over statement of transportation and other expenses used to calculate the net taxable value. Kinder Morgan CO₂ paid the retroactive tax bills under protest and filed petitions for a refund of the taxes paid under protest. A hearing on our petition occurred on December 19, 2011 before the Montezuma County Board of County Commissioners, and we await the Board's decision.

Other

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO₂'s payments on carbon dioxide produced from the McElmo Dome and Bravo Dome units are currently ongoing. These audits and inquiries involve federal agencies, the states of Colorado and New Mexico, and county taxing authorities in the state of Colorado.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and UPRR are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.*, Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial has concluded. In September 2011, the judge determined that the annual rent payable as of January 1, 2004 was \$14.8 million, subject to annual consumer price index increases. SFPP intends to appeal the judge's determination, but if that determination is upheld, SFPP would owe

approximately \$73.9 million in back rent. Accordingly, in 2011, we recorded a \$69.7 million expense and increased our rights-of-way liability related to this legal matter.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP appealed this decision, and in December 2008, the appellate court affirmed the decision. In addition, UPRR contends that SFPP must comply with the more expensive AREMA standards in determining when relocations are necessary and in completing relocations. Each party is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. A trial occurred in the fourth quarter of 2011, with a verdict having been reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. SFPP is evaluating its post-trial and appellate options.

Since SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position, our results of operations, and our cash flows. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal Sparrows Point, LLC and located in Sparrows Point, Maryland collapsed while being operated by KMBT. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the United States District Court for the District of Maryland, cause no. WMN 09CV1668. Severstal alleges that KMBT was contractually obligated to replace the collapsed crane and that its employees were negligent in failing to properly secure the crane prior to the collapse. Severstal seeks unspecified damages for value of the crane and lost profits. KMBT denies each of Severstal's allegations.

The Premcor Refining Group, Inc. v. Kinder Morgan Energy Partners, L.P. and Kinder Morgan Petcoke, L.P.; Arbitration in Houston, Texas

On August 12, 2010, Premcor filed a demand for arbitration against us and our subsidiary Kinder Morgan Petcoke, L.P., collectively referred to as Kinder Morgan, asserting claims for breach of contract. Kinder Morgan performs certain petroleum coke handling operations at the Port Arthur, Texas refinery that is the subject of the claim. The arbitration was administered by the American Arbitration Association in Dallas, Texas. Premcor alleged that Kinder Morgan breached its contract with Premcor by failing to properly manage the water level in the pit of a coker unit at a refinery owned by Premcor, failing to name Premcor as an additional insured, and failing to indemnify Premcor for claims brought against Premcor by PACC. PACC is a wholly owned subsidiary of Premcor. PACC brought its claims against Premcor in a previous separate arbitration seeking to recover damages allegedly suffered by PACC when a pit wall of a coker unit collapsed at its refinery. PACC obtained an arbitration award against Premcor in the amount of \$50.3 million, plus post-judgment interest. Premcor was seeking to hold Kinder Morgan liable for the award. Premcor was also seeking to recover an additional \$11.4 million of alleged losses and damages in excess of the amount it owes to PACC. The final arbitration hearing concluded on October 3, 2011. On October 21, 2011, we received the arbitrator's findings of fact and rulings of law, which determined that Kinder Morgan has no liability for damages with respect to the claims asserted by PACC in the prior arbitration or by Premcor in the present arbitration. The matter is now concluded.

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.

Westridge Release, Burnaby, British Columbia

On July 24, 2007, a third-party contractor installing a sewer line for the City of Burnaby struck a crude oil pipeline segment included within our Trans Mountain pipeline system near its Westridge terminal in Burnaby, British Columbia, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the British Columbia Ministry of Environment, the National Energy Board (Canada), and the National Transportation Safety Board (Canada). Cleanup and environmental remediation is complete, and we have received a British Columbia Ministry of Environment Certificate of Compliance confirming complete remediation.

Kinder Morgan Canada, Inc. commenced a lawsuit against the parties it believes were responsible for the third party strike, and a number of other parties have commenced related actions. All of the outstanding litigation was settled without assignment of fault on April 8, 2011. Kinder Morgan Canada has recovered the majority of its expended costs in responding to the third party strike.

On July 22, 2009, the British Columbia Ministry of Environment issued regulatory charges against the third-party contractor, the engineering consultant to the sewer line project, Kinder Morgan Canada Inc., and our subsidiary Trans Mountain L.P. The British Columbia Ministry of Environment claims that the parties charged caused the release of crude oil, and in doing so were in violation of various sections of the Environmental, Fisheries and Migratory Bird Act. On October 3, 2011, our subsidiary, Trans Mountain L.P., and each of the City of Burnaby's contractor and engineering consultant agreed to enter a plea of guilty to one count of The Environmental Management Act. Each party agreed to pay a \$1,000 fine and will contribute approximately \$0.1 million into a British Columbia environmental trust fund to be used for projects that benefit the environment and wildlife. In addition, Trans Mountain agreed to donate \$0.1 million to BC Common Ground Alliance to further develop and deliver education to contractors for working safely around pipelines. The Court confirmed the decision on November 10, 2011. All amounts have been paid, and all matters related to both the civil and regulatory action have been concluded.

Perth Amboy, New Jersey Tank Release

In May 2011, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, or NOPV, to KMLT. The notice alleges violations of PHMSA's regulations related to an October 28, 2009 tank release from our Perth Amboy, New Jersey liquids terminal. No product left the company's property, and additionally, there were no injuries, no impact to the adjacent community or public, and no fire as a result of the release. The notice proposes a penalty of approximately \$0.4 million. KMLT is pursuing an administrative appeal of the NOPV.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and no injuries associated with the incident. We immediately began clean up operations in coordination with federal, state and local agencies. The cause of the incident is outside force damage.

General

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is reasonably possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date and the reserves we have established, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. As of December 31, 2011 and December 31, 2010, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of \$331.9 million and \$169.8 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. The overall change in the reserve from December 31, 2010 includes both payments of \$81.4 million in 2011 (for interstate and California intrastate transportation rate settlements on our Pacific operations' pipelines) that reduced the liability, and a \$251.8 million

decrease in earnings in 2011 (largely associated with rate case liability adjustments that resulted in both increases in expense and decreases in revenues), which increased the liability. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

New Jersey Department of Environmental Protection v. Occidental Chemical Corporation, et al. (Defendants), Maxus Energy Corp. and Tierra Solutions, Inc. (Third Party Plaintiffs) v. 3M Company et al., Superior Court of New Jersey, Law Division – Essex County, Docket No. L-9868-05

The NJDEP sued Occidental Chemical and others under the New Jersey Spill Act for contamination in the Newark Bay Complex including numerous waterways and rivers. Occidental et al. then brought in approximately 300 third party defendants for contribution. NJDEP claimed damages related to forty years of discharges of TCDD (form of dioxin), DDT and “other hazardous substances.” GATX Terminals Corporation (n/k/a/ KMLT) was brought in as a third party defendant because of the noted hazardous substances language and because the Carteret, New Jersey facility (former GATX Terminals facility) is located on the Arthur Kill River, one of the waterways included in the litigation. This case was filed against third party defendants in 2009. The Judge issued his trial plan for this case during the first quarter of 2011. According to the trial plan, he allowed the State to file summary judgment motions against Occidental, Maxus and Tierra on liability issues immediately. Numerous third party defendants filed motions to dismiss, which were denied, and now have filed interlocutory appeals from those motions. KMLT is part of the third party defendant Joint Defense Group. We have filed an Answer and initial disclosures. The Judge put off trial of Maxus/Tierra’s claims against the third party defendants until April 2013 with damages to be tried in September 2013.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the U.S. EPA sent out 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. The major potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a non-voting member and pays a minimal fee to be part of the group. The LWG agreed to conduct the Remedial Investigation and Feasibility Study leading to the proposed remedy for cleanup of the Portland Harbor site. Once the U.S. EPA determines the cleanup remedy from the remedial investigations and feasibility studies conducted during the last decade at the site, it will issue a Record of Decision. Currently, KMLT and 90 other parties are involved in an allocation process to determine each party’s respective share of the cleanup costs. This is a non-judicial allocation process. We are participating in the allocation process on behalf of both KMLT and KMBT. Each entity has two facilities located in Portland Harbor. We expect the allocation to conclude in 2013 or 2014, depending upon when the U.S. EPA issues its Record of Decision.

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

This is a CERCLA case brought against a number of defendants by a water purveyor whose wells have allegedly been contaminated due to the presence of number of contaminants. The Roosevelt Irrigation District is seeking up to \$175 million from approximately 70 defendants. The plume of contaminates has traveled under Kinder Morgan’s Phoenix Terminal. The plaintiffs have advanced a novel theory that the releases of petroleum from the Phoenix Terminal (which are exempt under the petroleum exclusion under CERCLA) have facilitated the natural degradation of certain hazardous substances and thereby have resulted in a release of hazardous substances regulated under CERCLA. We are part of a joint defense group consisting of other terminal operators at the Phoenix Terminal including Chevron, BP, Salt River Project, Shell and a number of others, collectively referred to as the terminal defendants. Together, we filed a motion to dismiss all claims based on the petroleum exclusion under CERCLA. This case was recently assigned to a new judge, who has deemed all previous motions withdrawn and will grant leave to re-file such motions at a later date. We plan to re-file the motion to dismiss as well as numerous summary judgment motions.

Casper and Douglas, EPA Notice of Violation

In March 2011, the EPA conducted inspections of several environmental programs at the Douglas and Casper Gas Plants in Wyoming. In June 2011, we received two letters from the EPA alleging violations at both gas plants of the Risk Management Program requirements under the Clean Air Act. We are cooperating with the EPA and working with the EPA to resolve these allegations.

The City of Los Angeles v. Kinder Morgan Liquids Terminals, LLC, Shell Oil Company, Equilon Enterprises LLC; California Superior Court, County of Los Angeles, Case No. NC041463

KMLT is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed beginning in 2009 and remains stayed through the end of 2011. A hearing was held on December 13, 2010 to hear the City's motion to remove the litigation stay. At the hearing, the judge denied the motion to lift the stay without prejudice. At the next case management conference held on June 13, 2011, the judge again continued the full litigation stay. The Court continued the last case management conference until summer 2012. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup and are now starting a sampling and testing program at the site. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including KMLT, have appealed those cleanup goals to the state water board. The state water board has not yet taken any action with regard to our appeal petitions.

Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed \$10 million, and that the plaintiff's past damages exceed \$2 million. No trial date has yet been set.

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, LLC and ST Services, Inc.

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, and later owned by Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, and it too is a party to the lawsuit.

The complaint seeks any and all damages related to remediating all environmental contamination at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit. The parties engaged in court ordered mediation in 2008 through 2009, which did not result in settlement. The trial judge has issued a Case Management Order and the parties are actively engaged in discovery.

On June 25, 2007, the NJDEP, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against Exxon Mobil Corporation and KMLT, formerly known as GATX Terminals Corporation, alleging natural resource damages related to historic contamination at the Paulsboro terminal. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals/Plains seeking to bring Support Terminals/Plains into the case. Support Terminals/Plains filed motions to dismiss the third party complaints, which were denied. Support Terminals/Plains is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases. All private parties and the state participated in two mediation conferences in 2010.

In December 2010, KMLT and Plains Products entered into an agreement in principle with the NJDEP for settlement of the state's alleged natural resource damages claim. The parties then entered into a Consent Judgment which was subject to public notice and comment and court approval. The natural resource damage settlement includes a monetary award of \$1.1 million and a series of remediation and restoration activities at the terminal site. KMLT and Plains Products have joint responsibility for this settlement. Simultaneously, KMLT and Plains Products entered into a settlement agreement that settled each parties' relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now entered with the Court and the settlement is final. Now Plains will begin conducting remediation activities at the site and KMLT will provide oversight and 50% of the costs. The settlement with the state does not resolve the original complaint brought by ExxonMobil, however we are now approaching settlement discussions with ExxonMobil. There is no trial date set.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and MTBE impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. The City

disclosed in discovery that it is seeking approximately \$170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased their claim for damages to approximately \$365 million.

The Court issued a Case Management Order on January 6, 2011, setting dates for completion of discovery and setting a trial date. In April, 2011, the parties filed a joint stipulation to extend the discovery schedule by approximately 3 months. In December 2011, the parties again entered into a joint stipulation to extend the various schedules in the Court's Case Management Order. Now, the parties must complete all fact discovery by March 23, 2012. The parties participated in a mandatory settlement conference in November 2, 2011 but did not make any headway in settling the case. The trial is set for February 12, 2013. We have been and will continue to aggressively defend this action. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. We continue to be in compliance with this agency order as we conduct an extensive remediation effort at the City's stadium property site.

Kinder Morgan, EPA Section 114 Information Request

On January 8, 2010, Kinder Morgan Inc., on behalf of Natural Gas Pipeline Company of America LLC, Horizon Pipeline Company and Rockies Express Pipeline LLC, received a Clean Air Act Section 114 information request from the U.S. EPA, Region V. This information request requires that the three affiliated companies provide the U.S. EPA with air permit and various other information related to their natural gas pipeline compressor station operations located in Illinois, Indiana, and Ohio. The affiliated companies have responded to the request and believe the relevant natural gas compressor station operations are in substantial compliance with applicable air quality laws and regulations.

Notice of Proposed Debarment

In April 2011, we received Notices of Proposed Debarment from the U.S. EPA SDD. The Notices propose the debarment of us (along with four of our subsidiaries), Kinder Morgan, Inc., Kinder Morgan G.P., Inc., and Kinder Morgan Management, LLC, from participation in future federal contracting and assistance activities. The Notices allege that certain of the respondents' past environmental violations indicate a lack of present responsibility warranting debarment. Our objective is to fully comply with all applicable legal requirements and to operate our assets in accordance with our processes, procedures and compliance plans. We are performing better than industry averages in our incident rates and in our safety performance, all of which is publicly reported on our internet website. We take environmental compliance very seriously, and look forward to demonstrating our present responsibility to the U.S. EPA SDD through this administrative process and we are engaged in discussions with the U.S. EPA SDD with the goal of resolving this matter in a cooperative fashion. We do not anticipate that the resolution of this matter will have a material adverse impact on our business, financial position, results of operations or cash flows.

Other Environmental

We 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 law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide 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. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or cash flows.

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 cleanup.

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, natural gas liquids, natural gas and carbon dioxide. See “—Pipeline Integrity and Releases” above for additional information with respect to ruptures and leaks from our pipelines.

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 will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of December 31, 2011, we have accrued an environmental reserve of \$74.7 million, and we believe that these pending environmental matters will not have a material adverse impact on our business, financial position, results of operations or cash flows. In addition, as of December 31, 2011, we have recorded a receivable of \$5.3 million for expected cost recoveries that have been deemed probable. As of December 31, 2010, our environmental reserve totaled \$74.7 million and our estimated receivable for environmental cost recoveries totaled \$8.6 million. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

17. Regulatory Matters

The tariffs we charge for transportation on our interstate common carrier pipelines are subject to rate regulation by the FERC, under the Interstate Commerce Act. The Interstate Commerce Act requires, among other things, that interstate petroleum products pipeline rates be just and reasonable and nondiscriminatory. Pursuant to FERC Order No. 561, effective January 1, 1995, interstate petroleum products pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. FERC Order No. 561-A, affirming and clarifying Order No. 561, expanded the circumstances under which interstate petroleum products pipelines may employ cost-of-service ratemaking in lieu of the indexing methodology, effective January 1, 1995. For each of the years ended December 31, 2011, 2010 and 2009, the application of the indexing methodology did not significantly affect tariff rates on our interstate petroleum products pipelines.

Below is a brief description of our ongoing regulatory matters, including any material developments that occurred during 2011.

Kinder Morgan Interstate Gas Transmission Pipeline – Franklin to Hastings Expansion Project

KMIGT has filed a prior notice request to expand and replace certain mainline pipeline facilities to create up to 10,000 dekatherms per day of firm transportation capacity to serve an ethanol plant located near Aurora, Nebraska. The estimated cost of the facilities is \$18.4 million. The project was constructed and went into service on April 14, 2011.

FERC Natural Gas Fuel Tracker Proceedings

Trailblazer Pipeline Company LLC- Docket Nos. RP11-1939 and RP11-2168

On April 28, 2011, the FERC issued an Order Rejecting Tariff Record and Denying Waiver in Trailblazer Pipeline Company LLC’s annual fuel tracker filing at Docket No. RP11-1939-000. The order required Trailblazer to make a compliance filing for its annual Expansion Fuel Adjustment Percentage (EFAP) pursuant to its tariff. In its previous two annual tracker filings, Trailblazer received authorization by the FERC to defer collection of its fuel deferred account until a future period by granting a waiver of various fuel tracker provisions. In the Docket No. RP11-1939 filing, Trailblazer again asked for tariff waivers that would defer the collection of its fuel deferred account to a future period, which the FERC denied. Trailblazer has filed for rehearing of the FERC’s April 28, 2011 order, which is pending before the FERC.

On May 2, 2011, Trailblazer filed to re-determine its EFAP in compliance with the April 28, 2011 order, implementing a revised EFAP rate of 8.14%, which included the proposed recovery of the deferred account. On May 18, 2011, the FERC issued an order rejecting the May 2, 2011 filing, on the basis that the filing to implement a revised EFAP must be accomplished as a new proceeding, not as a compliance filing. Trailblazer has filed for rehearing of the May 18, 2011 order, which is also pending before the FERC.

On June 3, 2011, Trailblazer filed in a new proceeding, Docket No. RP11-2168-000, revised tariff records to redetermine its EFAP, with a proposed effective date of July 1, 2011. Trailblazer included three EFAP rate options. In addition, under two of the options, Trailblazer proposed to continue to defer collection of the deferred account until a future date. In an order dated July 1, 2011, referred to in this Note as the July 1 Order, the FERC rejected the two options to defer recovery of the deferred account and accepted the option that included recovery of the entire deferred account. Specifically, the FERC approved an EFAP rate of 8.69%, subject to refund, effective July 1, 2011 and established hearing proceedings to determine the appropriate throughput, revenue and cost data to use for determining the EFAP and the composition, accounting and proposed recovery methodology for amounts in the deferred account. In the July 1 Order, the FERC determined that Trailblazer could not charge negotiated rate shippers a fuel rate above the caps established in their negotiated rate agreements with Trailblazer and that operation of the cap was not an issue for hearing. As a result of this determination, Trailblazer recognized a \$13.1 million operating expense in the second quarter of 2011 for the amount of the deferred costs that is potentially attributable to the negotiated rate shippers. Trailblazer sought rehearing of the July 1 Order, and a prehearing conference held on July 14, 2011 established a procedural schedule that results in a hearing in April 2012.

Trailblazer and the active parties protesting this proceeding have been engaged in extensive settlement discussions that have resulted in settlement agreements and amendments to their negotiated rate agreements, which have been filed with the FERC. In order to facilitate such discussions, Trailblazer filed motions to suspend the procedural schedule to allow the parties time to finalize their settlements, which were granted by the Chief Judge. The FERC has issued orders accepting Trailblazer's negotiated rate filings with the protesting parties. On December 15, 2011, Trailblazer filed a motion to terminate the hearing procedure to resolve the issues raised in the proceeding and avoid the need for a hearing. As part of its motion, Trailblazer proposed certain concessions, including foregoing recovery of the deferred account balance accumulated through May 6, 2012, reducing the EFAP rate effective January 1, 2011 to reflect removal of amounts in such account, and withdrawing the pending requests for rehearing in Docket Nos. RP11-1939-000 and RP11-2168-000. On December 21, 2011, the administrative law judge issued an Initial Decision, stating that there are no issues in the case for him to decide in light of Trailblazer's concessions and ordered that the FERC rule on the remainder of the motion to terminate the proceedings. On December 29, 2011, given the non-opposition to the motion to terminate and the issuance of the Initial Decision, Trailblazer filed to reduce its EFAP from 8.69% to 4.78% effective January 1, 2012. The motion to terminate is pending before the FERC.

Trailblazer Pipeline Company LLC – Docket No. RP11-2295-000

On July 25, 2011, Trailblazer filed, in Docket No. RP11-2295-000, to apply the EFAP rate to additional classes of shippers, including interruptible transportation, backhaul transportation, and overrun transportation to be effective September 1, 2011. On August 31, 2011, the FERC issued an order rejecting Trailblazer's proposed tariff records on the basis that the tariff changes are contrary to Trailblazer's Docket No. RP10-492-000 Settlement and violate the prohibition against retroactive ratemaking by proposing to charge shippers for under-recoveries that occurred prior to the effective date of the tariff provision. Trailblazer has filed for rehearing of the August 31, 2011 order, which is pending before the FERC. Furthermore, Trailblazer does not expect the entire fuel tracker proceedings discussed above to have a material adverse impact on its business, financial position, results of operations or cash flows.

Rockies Express Pipeline LLC

On March 1, 2011, Rockies Express Pipeline LLC made its annual filing to revise its fuel lost and unaccounted for percentage, referred to as its FL&U rate, applicable to its shippers effective April 1, 2011. In this filing, Rockies Express requested an increase in its FL&U rate due to a decline in the price of natural gas used to index its FL&U rate that had resulted in a fuel tracker receivable balance as of December 31, 2010. Rockies Express proposed two options to allow it to recover these costs.

On March 30, 2011, the FERC notified Rockies Express that it had rejected the first option and that the second option, while accepted effective April 1, 2011, was under further FERC review. This event caused Rockies Express to reconsider the recoverability of a portion of its fuel tracker receivable balance that would have been recovered from one shipper. Therefore, in the first quarter of 2011, Rockies Express reduced its fuel tracker receivable balance by \$8.2 million and recorded the same amount as additional operations and maintenance expense.

Products Pipelines and Natural Gas Pipelines Regulatory Proceedings

For information on our pipeline regulatory proceedings, see Note 16 “Litigation, Environmental and Other Contingencies—Federal Energy Regulatory Commission Proceedings” and “—California Public Utilities Commission Proceedings.”

18. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates (ASU) that we adopted and that became effective January 1, 2011 had a material impact on our consolidated financial statements.

ASU No. 2011-04

On May 12, 2011, the FASB issued ASU No. 2011-04, “Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.” This ASU amends U.S. generally accepted accounting principles (U.S. GAAP) and results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and international financial reporting standards (IFRS). The amendments in this ASU change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements; however, the amendment’s requirements do not extend the use of fair value accounting, and for many of the requirements, the FASB did not intend for the amendments to result in a change in the application of the requirements in the “Fair Value Measurement” Topic of the Codification. Additionally, ASU No. 2011-04 includes some enhanced disclosure requirements, including an expansion of the information required for Level 3 fair value measurements. For us, ASU No. 2011-04 was effective January 1, 2012, and the adoption of this ASU did not have a material impact on our consolidated financial statements.

ASU Nos. 2011-05 and 2011-12

On June 16, 2011, the FASB issued ASU No. 2011-05, “Comprehensive Income (Topic 220): Presentation of Comprehensive Income.” This ASU eliminates the current option to report other comprehensive income and its components in the statement of changes in equity (statement of partners’ capital for us). An entity can elect to present items of net income and other comprehensive income in one continuous statement or in two separate, but consecutive, statements.

ASU No. 2011-05 also requires reclassifications of items out of accumulated other comprehensive income to net income to be measured and presented by income statement line item in both the statement where net income is presented and the statement where other comprehensive income is presented. However, on December 23, 2011, the FASB issued ASU No. 2011-12, “Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05” to defer this new requirement. For us, both ASU No. 2011-05 and ASU No. 2011-12 were effective January 1, 2012. Since these ASUs pertain to presentation and disclosure requirements only, the adoption of these ASUs did not have a material impact on our consolidated financial statements.

ASU No. 2011-08

On September 15, 2011, the FASB issued ASU No. 2011-8, “Intangibles—Goodwill and Other (Topic 350): Testing Goodwill for Impairment.” This ASU allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test prescribed by current accounting principles. However, the quantitative impairment test is required if an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to the quantitative goodwill impairment test, and then resume performing the qualitative assessment in any subsequent period. For us, ASU No. 2011-8 was effective January 1, 2012, and the adoption of this ASU did not have a material impact on our consolidated financial statements. Furthermore, we perform our annual goodwill impairment test on May 31 each year, and we do not expect the adoption of this ASU to have a material impact on our May 31, 2012 goodwill impairment test.

ASU No. 2011-09

On September 21, 2011, the FASB issued ASU No. 2011-9, “Compensation—Retirement Benefits—Multiemployer Plans (Subtopic 715-80): Disclosures about an Employer’s Participation in a Multiemployer Plan.” The amendments in this ASU require that employers provide, on an annual basis, additional separate disclosures for all individually significant multiemployer pension plans and multiemployer other postretirement benefit plans. The revisions do not change the current recognition and measurement guidance for an employer’s participation in a multiemployer plan. For us, ASU No. 2011-9 was effective December 31, 2011; however, because we consider our overall multi-employer pension plan liability exposure and multi-employer pension plan contributions to be minimal in relation to the value of our total consolidated assets and net income (and not material to our consolidated financial statements), the adoption of this ASU did not have a material impact on our consolidated financial statements.

ASU No. 2011-11

On December 16, 2011, the FASB issued ASU No. 2011-11, “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.” This ASU requires disclosures to provide information to help reconcile differences in the offsetting requirements under U.S. GAAP and IFRS. The disclosure requirements of this ASU mandate that entities disclose both gross and net information about financial instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an enforceable master netting arrangement or similar agreement. ASU No. 2011-11 also requires disclosure of collateral received and posted in connection with master netting arrangements or similar arrangements. The scope of this ASU includes derivative contracts, repurchase agreements, and securities borrowing and lending arrangements. Entities are required to apply the amendments of ASU No. 2011-11 for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. All disclosures provided by those amendments are required to be provided retrospectively for all comparative periods presented. We are currently reviewing the effect of ASU No. 2011-11.

19. Quarterly Financial Data (Unaudited)

	Operating Revenues	Operating Income	Net Income	Limited Partners’ Net Income (Loss) per Unit
	(In millions, except per unit amounts)			
2011				
First Quarter(a).....	\$ 1,992.8	\$ 409.1	\$ 340.9	\$ 0.18
Second Quarter(b).....	2,019.3	290.2	231.9	(0.19)
Third Quarter(c).....	2,195.1	448.9	216.3	(0.25)
Fourth Quarter.....	2,004.0	522.3	479.3	0.51
2010				
First Quarter(d).....	\$ 2,129.6	\$ 287.9	\$ 227.4	\$ (0.08)
Second Quarter.....	1,961.5	443.6	365.1	0.88
Third Quarter.....	2,060.0	407.3	322.4	0.17
Fourth Quarter.....	1,926.6	466.3	412.2	0.42

(a) First quarter 2011 includes an \$87.1 million increase in expense allocated to us from KMI and associated with a one-time special cash bonus payment paid to non-senior management employees in May 2011; however, we do not have any obligation, nor did we pay any amounts related to this expense.

(b) Second quarter 2011 includes a \$165.0 million increase in expense associated with rate case liability adjustments.

(c) Third quarter 2011 includes a \$167.2 million loss from the remeasurement of our previously held 50% equity interest in KinderHawk Field Services LLC to fair value, and a \$69.3 million increase in expense primarily associated with rights-of-way lease payment liability adjustments.

(d) First quarter 2010 includes a \$158.0 million increase in expense associated with rate case liability adjustments.

20. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Operating statistics from our oil and gas producing activities for each of the years 2011, 2010 and 2009 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d).....	\$ 15.37	\$ 12.58	\$ 11.44
Crude oil production (MBbl/d).....	34.2	35.5	37.4
SACROC crude oil production (MBbl/d).....	23.8	24.3	25.1
Yates crude oil production (MBbl/d).....	9.6	10.7	11.8
Natural gas liquids production (MBbl/d)(d).....	3.5	5.8	5.4
Natural gas liquids production from gas plants(MBbl/d)(e).....	5.0	4.2	4.0
Total natural gas liquids production(MBbl/d).....	8.5	10.0	9.4
SACROC natural gas liquids production (MBbl/d)(d).....	3.3	5.5	5.3
Yates natural gas liquids production (MBbl/d)(d).....	0.2	0.2	0.1
Natural gas production (MMcf/d)(d)(f).....	1.5	1.4	0.9
Natural gas production from gas plants(MMcf/d)(e)(f).....	0.5	1.9	0.7
Total natural gas production(MMcf/d)(f).....	2.0	3.3	1.6
Yates natural gas production (MMcf/d)(d)(f).....	1.4	1.3	0.8
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g).....	\$ 69.73	\$ 59.96	\$ 49.55
Natural gas liquids price per Bbl(g).....	\$ 65.65	\$ 50.34	\$ 37.70
Natural gas price per Mcf(h).....	\$ 3.86	\$ 4.08	\$ 3.45
Total natural gas liquids price per Bbl(e).....	\$ 65.61	\$ 51.03	\$ 37.96
Total natural gas price per Mcf(e).....	\$ 3.76	\$ 4.10	\$ 3.53
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g).....	\$ 92.61	\$ 76.93	\$ 59.03
Natural gas liquids price per Bbl(g).....	\$ 65.65	\$ 50.34	\$ 37.70
Natural gas price per Mcf(h).....	\$ 3.86	\$ 4.08	\$ 3.45

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries.

(b) Computed using production costs, excluding transportation costs, as defined by the SEC. Natural gas volumes were converted to barrels of oil equivalent using a conversion factor of six mcf of natural gas to one barrel of oil.

(c) Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, and general and administrative expenses directly related to oil and gas producing activities.

(d) Includes only production attributable to leasehold ownership.

(e) Includes production attributable to our ownership in processing plants and third party processing agreements.

(f) Excludes natural gas production used as fuel.

(g) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(h) Natural gas sales were not hedged.

The following three tables provide supplemental information on oil and gas producing activities, including (i) capitalized costs related to oil and gas producing activities; (ii) costs incurred for the acquisition of oil and gas producing properties and for exploration and development activities; and (iii) the results of operations from oil and gas producing activities.

Our capitalized costs consisted of the following (in millions):

Capitalized Costs Related to Oil and Gas Producing Activities

	As of December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Wells and equipment, facilities and other.....	\$ 3,103.6	\$ 2,676.8	\$ 2,428.6
Leasehold	352.3	352.3	352.6
Total proved oil and gas properties	3,455.9	3,029.1	2,781.2
Unproved property(b).....	34.3	88.3	10.2
Accumulated depreciation and depletion.....	(2,288.0)	(1,901.0)	(1,501.1)
Net capitalized costs	<u>\$ 1,202.2</u>	<u>\$ 1,216.4</u>	<u>\$ 1,290.3</u>

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries. Includes capitalized asset retirement costs and associated accumulated depreciation.

(b) The unproved amounts consist of capitalized costs related to the Katz Unit, which is in the initial stages of the carbon dioxide flooding operation.

For each of the years 2011, 2010 and 2009, our costs incurred for property acquisition, exploration and development were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Property acquisitions - proved oil and gas properties....	\$ -	\$ -	\$ 5.3
Development.....	372.8	326.0	330.3

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries. During 2011, we spent \$89.0 million on development costs related to the Katz field unit, which was in the initial stages of the carbon dioxide flooding operation. As of December 31, 2011, capitalized costs related to unproved property for the Katz unit was \$34.3 million. No exploration costs were incurred for the periods reported.

Our results of operations from oil and gas producing activities for each of the years 2011, 2010 and 2009 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Revenues(b).....	\$ 993.0	\$ 903.2	\$ 767.0
Expenses:			
Production costs.....	245.8	229.5	188.8
Other operating expenses(c)	79.5	62.7	53.3
Depreciation, depletion and amortization expenses.....	394.1	406.3	441.4
Total expenses.....	<u>719.4</u>	<u>698.5</u>	<u>683.5</u>
Results of operations for oil and gas producing activities....	<u>\$ 273.6</u>	<u>\$ 204.7</u>	<u>\$ 83.5</u>

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries.

(b) Revenues include losses attributable to our hedging contracts of \$285.2 million, \$219.9 million and \$129.5 million for each of the years ended December 31, 2011, 2010 and 2009, respectively.

(c) Consists primarily of carbon dioxide expense.

Supplemental information is also provided for the following three items (i) estimated quantities of proved oil and gas reserves; (ii) the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and (iii) a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

The technical persons responsible for preparing the reserves estimates presented in this Note meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. They are independent petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our oil and gas properties; and we do not employ them on a contingent basis. Our employee who is primarily responsible for overseeing Netherland, Sewell and Associate, Inc.'s preparation of the reserves estimates is a registered Professional Engineer in the states of Texas and Kansas with a Doctorate of Engineering from the University of Kansas. He is a member of the Society of Petroleum Engineers and has over 25 years of professional engineering experience.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Derek Newton and Mr. Mike Norton. Mr. Newton has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Newton is a Licensed Professional Engineer in the State of Texas (No. 97689) and has over 26 years of practical experience in petroleum engineering, with over 14 years experience in the estimation and evaluation of reserves. He graduated from University College, Cardiff, Wales, in 1983 with a Bachelor of Science Degree in Mechanical Engineering and from Strathclyde University, Scotland, in 1986 with a Master of Science Degree in Petroleum Engineering. Mr. Norton has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 22 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

We believe the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information becomes available and contractual and economic conditions change.

Furthermore, our management is responsible for establishing and maintaining adequate internal control over financial reporting, which includes the estimation of our oil and gas reserves. We maintain internal controls and guidance to ensure the reliability of our crude oil, natural gas liquids and natural gas reserves estimations, as follows:

- no employee's compensation is tied to the amount of recorded reserves;
- we follow comprehensive SEC compliant internal policies to determine and report proved reserves, and our reserve estimates are made by experienced oil and gas reservoir engineers or under their direct supervision;
- we review our reported proved reserves at each year-end, and at each year-end, our CO₂ business segment managers and our Vice President (President, CO₂) review all significant reserves changes and all new proved developed and undeveloped reserves additions; and
- our CO₂ business segment reports independently of our four remaining reportable business segments.

For more information on our controls and procedures, see Item 9A "Controls and Procedures—Management's Report on Internal Control Over Financial Reporting" included in our Annual Report on Form 10-K for the year ended December 31, 2011.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known

reservoirs under existing economic and operating conditions, that is, current prices and costs calculated as of the date the estimate is made. Pricing is applied based upon the twelve month unweighted arithmetic average of the first day of the month price for the year. Future development and production costs are determined based upon actual cost at year-end. Proved developed reserves are the quantities of crude oil, natural gas liquids and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

As of December 31, 2009, we had 47.0 million barrels of crude oil and 2.7 million barrels of natural gas liquids classified as proved developed reserves. Also as of year end 2009, we had 33.8 million barrels of crude oil and 3.2 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2009 were 80.8 million barrels of oil and 5.9 million barrels of natural gas liquids.

During 2010, production from the fields totaled 13.0 million barrels of crude oil and 2.1 million barrels of natural gas liquids. In addition, we incurred \$248.0 million in capital costs which resulted in the development of 10.0 million barrels of crude oil and 1.3 million barrels of natural gas liquids and their transfer from the proved undeveloped category to the proved developed category. These reclassifications reflect the transfer of 29.6% of crude oil and 39.9% of natural gas liquids from the proved undeveloped reserves reported as of December 31, 2009 to the proved developed classification of reserves reported as of December 31, 2010.

Also during 2010, previous estimates of proved developed reserves were revised upwards by 12.3 million barrels of crude oil and 0.4 million barrels of natural gas liquids, and proved undeveloped reserves were revised upward by 4.0 million barrels of crude oil and 0.7 million barrels of natural gas liquids. Almost 90 percent of the revisions were associated with our third party oil and gas consultants revising the methodology used to estimate reserves for our Yates Field Unit in order to take greater account of the reservoir mechanisms associated with carbon dioxide injection, for which there are now seven years of history. The revised methodology used to forecast the Yates Field Unit future performance utilizes a volume balance that is based on a correlation of historical production to observed oil saturations and reservoir volume factors during the life of the Yates Field Unit, with emphasis on the period from 1996 through 2010. A portion of these revisions were attributed to utilizing a higher prescribed oil price basis to calculate reserves (\$75.96 per barrel for year end 2010 versus \$57.65 per barrel for year end 2009).

These revisions to our previous estimates, as well as the transfer of proved undeveloped reserves to the proved developed category as discussed above, resulted in the percentage of proved undeveloped reserves decreasing from 42.6% at year end 2009 to 33.9% at year end 2010. After giving effect to production and revisions to previous estimates during 2010, total proved reserves of crude oil increased by 3.3 million barrels and total proved reserves of natural gas liquids decreased by 1.1 million barrels.

As of December 31, 2010, we had 56.4 million barrels of crude oil and 2.2 million barrels of natural gas liquids classified as proved developed reserves. Also, as of year end 2010, we had 27.8 million barrels of crude oil and 2.6 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2010, were 84.2 million barrels of crude oil and 4.9 million barrels of natural gas liquids.

During 2011, production from the fields totaled 12.5 million barrels of crude oil and 1.3 million barrels of natural gas liquids. For 2011, we incurred \$372.8 million in capital costs, and in prior years, we incurred \$43.6 million in capital costs related to the Katz field unit. Combined, these capital investments resulted in the development of 7.3 million barrels of crude oil and 0.9 million barrels of natural gas liquids and their transfer from the proved undeveloped category to the proved developed category. We also developed 3.0 million barrels of crude oil and 0.0 million barrels of natural gas liquids reserves with the development of the Katz (Strawn) unit CO₂ flood where the produced gas containing natural gas liquids is injected with the CO₂. The reclassifications from proved undeveloped to proved developed reserves reflect the transfer of 26.2% of crude oil and 35.2% of natural gas liquids from the proved undeveloped reserves reported as of December 31, 2010 to the proved developed classification of reserves reported as of December 31, 2011. The developed reserves for the Katz (Strawn) unit CO₂ flood represent 5.4% of proved developed reserves.

Also during 2011, previous estimates of proved developed reserves were revised upwards by 1.4 million barrels of crude oil and 0.0 million barrels of natural gas liquids, and proved undeveloped reserves were revised upward by 3.3 million barrels of crude oil and 0.6 million barrels of natural gas liquids. These revisions are attributed to utilizing a higher prescribed oil price basis (\$92.71 per barrel for year end 2011 versus \$75.96 per barrel for year end 2010) and higher projected CO₂ flood recoveries resulting from updated performance at SACROC used to calculate reserves. All natural gas reserves are associated with crude oil production and are not impacted by gas pricing.

These revisions to our previous estimates, as well as the transfer of proved undeveloped reserves to the proved developed category as discussed above, resulted in the percentage of proved undeveloped reserves decreasing from 33.9% at year end 2010 to 31.0% at year end 2011. After giving effect to production and revisions to previous estimates during 2011, total proved reserves of crude oil decreased by 4.7 million barrels and total proved reserves of natural gas liquids decreased by 0.7 million barrels.

As of December 31, 2011, we had 55.7 million barrels of crude oil and 1.8 million barrels of natural gas liquids classified as proved developed reserves. Also, as of year end 2011, we had 23.8 million barrels of crude oil and 2.3 million barrels of natural gas liquids classified as proved undeveloped reserves. Total proved reserves as of December 31, 2011, were 79.4 million barrels of crude oil and 4.1 million barrels of natural gas liquids. We currently expect that the proved undeveloped reserves we report as of December 31, 2011 will be developed within the next five years.

During 2011, we filed estimates of our oil and gas reserves for the year 2010 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23. The data on Form EIA-23 was presented on a different basis, and included 100% of the oil and gas volumes from our operated properties only, regardless of our net interest. The difference between the oil and gas reserves reported on Form EIA-23 and those reported in this Note exceeds 5%.

The following Reserve Quantity Information table discloses estimates, as of December 31, 2011, of proved crude oil, natural gas liquids and natural gas reserves, prepared by Netherland, Sewell and Associates, Inc. (independent oil and gas consultants), of Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries' interests in oil and gas properties, all of which are located in the state of Texas. This data has been prepared using current prices and costs, as discussed above, and the estimates of reserves and future revenues in this Note conform to the guidelines of the U.S. Securities and Exchange Commission (SEC).

Reserve Quantity Information

	Consolidated Companies(a)		
	Crude Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)(b)
Proved developed and undeveloped reserves:			
As of December 31, 2008	78,579	6,860	1,274
Revisions of previous estimates(c)	15,900	1,018	(293)
Production	(13,688)	(1,995)	(298)
Purchases of reserves in place	53	37	15
As of December 31, 2009	80,844	5,920	698
Revisions of previous estimates(d)	16,294	1,059	2,923
Production	(12,962)	(2,116)	(523)
As of December 31, 2010	84,176	4,863	3,098
Revisions of previous estimates(e)	4,719	567	687
Improved recovery(f)	3,018	-	-
Production	(12,466)	(1,285)	(544)
As of December 31, 2011	79,447	4,145	3,241
Proved developed reserves:			
As of December 31, 2009	47,058	2,665	698
As of December 31, 2010	56,423	2,221	3,098
As of December 31, 2011	55,652	1,823	3,241
Proved undeveloped reserves:			
As of December 31, 2009	33,786	3,255	-
As of December 31, 2010	27,753	2,642	-
As of December 31, 2011	23,795	2,322	-

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries.

(b) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees fahrenheit.

(c) Predominantly due to higher product prices resulting in an expanded economic carbon dioxide project area.

(d) Predominantly due to higher product prices used to determine reserve volumes and the change in methodology discussed above.

- (e) Predominantly due to higher product prices used to determine reserve volumes.
- (f) Represents volumes added with the development of the Katz (Strawn) unit carbon dioxide flood.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year-to-year are prepared in accordance with the “Extractive Activities—Oil and Gas” Topic of the Codification. The assumptions that underly the computation of the standardized measure of discounted cash flows, presented in the table below, may be summarized as follows:

- the standardized measure includes our estimate of proved crude oil, natural gas liquids and natural gas reserves and projected future production volumes based upon year-end economic conditions;
- pricing is applied based upon the 12 month unweighted arithmetic average of the first day of the month price for the year;
- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

Our standardized measure of discounted future net cash flows from proved reserves were as follows (in millions):

**Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves**

	As of December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Future cash inflows from production.....	\$ 7,648.1	\$ 6,665.8	\$ 4,898.0
Future production costs	(2,806.5)	(2,387.9)	(1,951.5)
Future development costs(b)	(1,443.0)	(1,433.7)	(1,179.7)
Undiscounted future net cash flows	3,398.6	2,844.2	1,766.8
10% annual discount	(1,204.6)	(946.6)	(503.5)
Standardized measure of discounted future net cash flows.....	<u>\$ 2,194.0</u>	<u>\$ 1,897.6</u>	<u>\$ 1,263.3</u>

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries.

(b) Includes abandonment costs.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

**Changes in the Standardized Measure of Discounted Future Net Cash Flows From
Proved Oil and Gas Reserves**

	As of December 31,		
	2011	2010	2009
Consolidated Companies(a)			
Present value as of January 1	\$ 1,897.6	\$ 1,263.3	\$ 658.4
Changes during the year:			
Revenues less production and other costs(b)	(949.5)	(828.2)	(652.7)
Net changes in prices, production and other costs(b)	696.9	890.0	915.7
Development costs incurred	416.4	248.0	330.3
Net changes in future development costs	(316.7)	(296.6)	(445.4)
Improved recovery	10.2	-	-
Revisions of previous quantity estimates(c)	257.1	494.2	391.1
Accretion of discount	182.0	126.9	65.9
Net change for the year	296.4	634.3	604.9
Present value as of December 31	<u>\$ 2,194.0</u>	<u>\$ 1,897.6</u>	<u>\$ 1,263.3</u>

(a) Amounts relate to Kinder Morgan CO₂ Company, L.P. and its consolidated subsidiaries.

(b) Excludes the effect of losses attributable to our hedging contracts of \$285.2 million, \$219.9 million and \$129.5 million for each of the years ended December 31, 2011, 2010 and 2009, respectively.

(c) 2011 revisions were primarily due to higher product prices used to determine reserve volumes and the addition of the Katz (Strawn) carbon dioxide flood. 2010 revisions were primarily due to higher product prices used to determine reserve volumes and the change in methodology discussed above. 2009 revisions were primarily due to higher product prices resulting in an expanded economic carbon dioxide project area.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 ENERGY PARTNERS, L.P.
Registrant (a Delaware Limited Partnership)

By: **KINDER MORGAN G.P., INC.**,
Its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC**, the
Delegate of Kinder Morgan G.P., Inc.

By: /s/ KIMBERLY A. DANG
Kimberly A. Dang,
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 17, 2012

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ KIMBERLY A. DANG</u> Kimberly A. Dang	Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal financial officer and principal accounting officer)	February 17, 2012
<u>/s/ RICHARD D. KINDER</u> Richard D. Kinder	Chairman of the Board and Chief Executive Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal executive officer)	February 17, 2012
<u>/s/ TED A. GARDNER</u> Ted A. Gardner	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 17, 2012
<u>/s/ GARY L. HULTQUIST</u> Gary L. Hultquist	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 17, 2012
<u>/s/ PERRY M. WAUGHTAL</u> Perry M. Waughtal	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 17, 2012
<u>/s/ C. PARK SHAPER</u> C. Park Shaper	Director and President of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 17, 2012