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

F O R M 10-Q

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

For the quarterly period ended June 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	**76-0380342**
(State or other jurisdiction of incorporation or organization)	(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 [X] 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 [X] 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 [X] 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 [X]

The Registrant had 240,140,446 common units outstanding as of July 27, 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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenues				
Natural gas sales	$ 497	$ 847	$ 1,081	$ 1,650
Services	737	712	1,498	1,453
Product sales and other	618	379	1,121	752
Total Revenues	1,852	1,938	3,700	3,855
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	624	843	1,204	1,636
Operations and maintenance	336	468	642	764
Depreciation, depletion and amortization	248	223	487	438
General and administrative	98	98	205	287
Taxes, other than income taxes	51	50	101	96
Other expense (income)	(20)	(14)	(20)	(14)
Total Operating Costs, Expenses and Other	1,337	1,668	2,619	3,207
Operating Income	515	270	1,081	648
Other Income (Expense)				
Earnings from equity investments	67	56	132	103
Amortization of excess cost of equity investments	(2)	(2)	(4)	(3)
Interest expense	(142)	(130)	(282)	(262)
Interest income	5	6	10	10
Other, net	9	7	10	8
Total Other Income (Expense)	(63)	(63)	(134)	(144)
Income from Continuing Operations Before Income Taxes	452	207	947	504
Income Tax (Expense) Benefit	(14)	(15)	(29)	(21)
Income from Continuing Operations	438	192	918	483
Discontinued Operations (Note 2)				
Income from operations of FTC Natural Gas Pipelines disposal group	48	40	98	90
Loss on remeasurement of FTC Natural Gas Pipelines disposal group to fair value	(327)	—	(649)	—
Income (Loss) from Discontinued Operations	(279)	40	(551)	90
Net Income	159	232	367	573
Net Income Attributable to Noncontrolling Interests	(6)	(2)	(8)	(5)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 153	$ 230	$ 359	$ 568
Calculation of Limited Partners' Interest in Net Income (Loss) Attributable to Kinder Morgan Energy Partners, L.P.:				
Income from Continuing Operations	$ 429	$ 191	$ 904	$ 479
Less: General Partner's Interest	(336)	(292)	(657)	(572)
Limited Partners' Interest	93	(101)	247	(93)
Add: Limited Partners' Interest in Discontinued Operations	(274)	39	(540)	88
Limited Partners' Interest in Net Loss	$ (181)	$ (62)	$ (293)	$ (5)
Limited Partners' Net Income (Loss) per Unit:				
Income (Loss) from Continuing Operations	$ 0.27	$ (0.31)	$ 0.73	$ (0.29)
Income (Loss) from Discontinued Operations	(0.80)	0.12	(1.59)	0.27
Net Loss	$ (0.53)	$ (0.19)	$ (0.86)	$ (0.02)
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income (Loss) per Unit	342	321	340	319
Per Unit Cash Distribution Declared	$ 1.23	$ 1.15	$ 2.43	$ 2.29

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Net Income	$ 159	$ 232	$ 367	$ 573
Other Comprehensive Income (Loss):				
Change in fair value of derivatives utilized for hedging purposes	303	165	189	(98)
Reclassification of change in fair value of derivatives to net income	(11)	87	20	140
Foreign currency translation adjustments	(40)	10	(2)	61
Adjustments to pension and other postretirement benefit plan liabilities, net of tax	—	—	(1)	(13)
Total Other Comprehensive Income	252	262	206	90
Comprehensive Income	411	494	573	663
Comprehensive Income Attributable to Noncontrolling Interests	(9)	(4)	(10)	(5)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 402	$ 490	$ 563	$ 658

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)

	June 30, 2012	December 31, 2011
ASSETS	(Unaudited)	
Current assets		
Cash and cash equivalents	$ 522	$ 409
Accounts, notes and interest receivable, net	822	884
Inventories	186	110
Gas in underground storage	45	62
Fair value of derivative contracts	113	72
Assets held for sale	1,938	—
Other current assets	51	39
Total Current assets	3,677	1,576
Property, plant and equipment, net	15,130	15,596
Investments	2,087	3,346
Notes receivable	163	165
Goodwill	1,351	1,436
Other intangibles, net	1,112	1,152
Fair value of derivative contracts	710	632
Deferred charges and other assets	184	200
Total Assets	$ 24,414	$ 24,103
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 979	$ 1,638
Cash book overdrafts	27	21
Accounts payable	682	706
Accrued interest	260	259
Accrued taxes	77	38
Deferred revenues	96	100
Fair value of derivative contracts	31	121
Accrued other current liabilities	329	236
Total Current liabilities	2,481	3,119
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	12,154	11,159
Debt fair value adjustments	1,136	1,079
Total Long-term debt	13,290	12,238
Deferred income taxes	256	250
Fair value of derivative contracts	6	39
Other long-term liabilities and deferred credits	814	853
Total Long-term liabilities and deferred credits	14,366	13,380
Total Liabilities	16,847	16,499
Commitments and contingencies (Notes 3 and 9)		
Partners' Capital		
Common units	4,170	4,347
Class B units	24	42
i-units	2,772	2,857
General partner	282	259
Accumulated other comprehensive income	207	3
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	7,455	7,508
Noncontrolling interests	112	96
Total Partners' Capital	7,567	7,604
Total Liabilities and Partners' Capital	$ 24,414	$ 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)

	Six Months Ended June 30,	
	2012	**2011**
Cash Flows From Operating Activities		
Net Income	$ 367	$ 573
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on remeasurement of FTC Natural Gas Pipelines disposal group to fair value (Note 2)	649	—
Depreciation, depletion and amortization	494	451
Amortization of excess cost of equity investments	4	3
Noncash compensation expense allocated from parent (Note 8)	—	90
Earnings from equity investments	(174)	(141)
Distributions from equity investments	159	136
Proceeds from termination of interest rate swap agreements	53	—
Changes in components of working capital:		
Accounts receivable	55	55
Inventories	(90)	12
Other current assets	(6)	(71)
Accounts payable	(25)	15
Cash book overdrafts	6	(13)
Accrued interest	1	4
Accrued taxes	44	19
Accrued liabilities	66	(10)
Rate reparations, refunds and other litigation reserve adjustments	(54)	102
Other, net	(45)	14
Net Cash Provided by Operating Activities	1,504	1,239
Cash Flows From Investing Activities		
Acquisitions of assets and investments	(30)	(110)
Repayments from related party	—	1
Capital expenditures	(777)	(535)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	15	17
(Investments in) Net proceeds from margin and restricted deposits	(1)	49
Contributions to equity investments	(86)	(60)
Distributions from equity investments in excess of cumulative earnings	86	121
Refined products, natural gas liquids and transmix line-fill	(21)	—
Net Cash Used in Investing Activities	(814)	(517)
Cash Flows From Financing Activities		
Issuance of debt	3,438	3,515
Payment of debt	(3,093)	(3,641)
Debt issue costs	(5)	(8)
Proceeds from issuance of common units	277	706
Contributions from noncontrolling interests	17	13
Distributions to partners and noncontrolling interests:		
Common units	(551)	(499)
Class B units	(13)	(12)
General Partner	(630)	(562)
Noncontrolling interests	(15)	(13)
Net Cash Used in Financing Activities	(575)	(501)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(2)	3
Net increase in Cash and Cash Equivalents	113	224
Cash and Cash Equivalents, beginning of period	409	129
Cash and Cash Equivalents, end of period	$ 522	$ 353

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)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Noncash Investing and Financing Activities		
Assets acquired or liabilities settled by the issuance of common units	$ 296	$ 24
Assets acquired by the assumption or incurrence of liabilities	$ —	$ 10
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)	$ 277	$ 261
Cash paid during the period for income taxes	$ 11	$ 10

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 29,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described further in Note 7). 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 CO_2, 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 June 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 12.2% interest in us.

On October 16, 2011, KMI and El Paso Corporation (EP) announced a definitive agreement whereby KMI would acquire all of the outstanding shares of EP in a transaction that would create one of the largest energy companies in the United States. On March 2, 2012, 100% of KMI's shareholders that voted approved the proposed EP acquisition, and on March 9, 2012, more than 95% of EP shareholders that voted approved the acquisition. The transaction was effective May 25, 2012.

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 each of the assets 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 the third quarter of 2012. Furthermore, we expect KMI to offer to sell (drop-down) all of the Tennessee Gas Pipeline system and a 50% ownership interest in the El Paso Natural Gas pipeline system to us in order to replace the assets that we will divest, and we expect that these drop-downs will also occur in the third quarter of 2012. For more information about this planned divestiture, see both "—Basis of Presentation" below and Note 2.

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 8 "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 on 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 six months ended June 30, 2012; and (iii) reclassified and reported the disposal group's combined assets separately as "Assets held for sale" in our accompanying consolidated balance sheet as of June 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 June 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.

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); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2012 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

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

Acquisitions

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 June 30, 2012, our net equity investment in the joint venture totaled $290 million and is included within "Investments" on our accompanying consolidated balance sheet.

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 quarter of 2012 to reflect our initial assessment of its fair value as a result of the FTC mandated sale requirement. Based on additional information gained in the sale process, we have recognized an additional adjustment in the current quarter for a combined $649 million non-cash loss. We reported this loss amount separately as "Loss on 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 six months ended June 30, 2012. We also reclassified the fair value of the disposal group's assets as "held for sale" assets in our accompanying consolidated balance sheet as of June 30, 2012 (because the disposal group's combined liabilities were not material to our consolidated balance sheet as of June 30, 2012, we included the disposal group's liabilities within "Accrued other current liabilities"). "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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Operating revenues	$ 62	$ 82	$ 133	$ 158
Operating expenses	(34)	(56)	(71)	(94)
Depreciation and amortization	—	(6)	(7)	(13)
Earnings from equity investments	20	20	42	38
Interest income and Other, net	—	—	1	1
Earnings from discontinued operations	$ 48	$ 40	$ 98	$ 90

3. Debt

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

	June 30, 2012	December 31, 2011
Current portion of debt(a)	$ 979	$ 1,638
Long-term portion of debt	12,154	11,159
Net carrying value of debt(b)	$ 13,133	$ 12,797

(a) As of June 30, 2012 and December 31, 2011, includes commercial paper borrowings of $446 million and $645 million, respectively.

(b) Excludes debt fair value adjustments. As of June 30, 2012 and December 31, 2011, the value of our interest rate swap agreements, including any unamortized portion of proceeds received from the early termination of interest rate swap agreements, totaled $1,136 million and $1,079 million, respectively.

Changes in our outstanding debt during the six months ended June 30, 2012 are summarized as follows (in millions):

Debt borrowings	Interest rate	Increase / (decrease)	Cash received / (paid)
Issuances and discount amortization			
Senior notes due September 1, 2022(a)	3.95%	$ 998	$ 998
Commercial paper	variable	2,440	2,440
Credit facility	variable	—	—
Discount amortization	various	1	—
Total increases in debt		$ 3,439	$ 3,438
Repayments and other			
Senior notes due March 15, 2012(a)	7.125%	$ (450)	$ (450)
Commercial paper	variable	(2,638)	(2,638)
Credit facility	variable	—	—
Kinder Morgan Texas Pipeline, L.P. - senior notes due January 2, 2014	5.23%	(4)	(4)
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		$ (3,103)	$ (3,093)

(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.

We had, as of June 30, 2012, approximately $1.5 billion of borrowing capacity available under our $2.2 billion senior unsecured revolving credit facility. As of June 30, 2012, the amount available for borrowing under our credit facility was reduced by a combined amount of $672 million, consisting of $446 million of commercial paper borrowings and $226 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; (iv) an $11 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined $17 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.

4. Partners' Capital

Limited Partner Units

As of June 30, 2012 and December 31, 2011, our partners' capital included the following limited partner units:

	June 30, 2012	December 31, 2011
Common units	239,971,640	232,677,222
Class B units	5,313,400	5,313,400
i-units	101,577,509	98,509,389
Total limited partner units	346,862,549	336,500,011

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 both June 30, 2012 and December 31, 2011, (i) KMI and its consolidated affiliates (excluding our general partner) held 14,646,428 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 six month periods ended June 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):

	Six Months Ended June 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	277	—	277	706	—	706
Units issued as consideration in the acquisition of assets	296	—	296	24	—	24
Distributions paid in cash	(1,194)	(15)	(1,209)	(1,073)	(13)	(1,086)
Noncash compensation expense allocated from KMI(a)	—	—	—	89	1	90
Cash contributions	—	17	17	—	13	13
Other adjustments	5	4	9	1	—	1
Comprehensive income	563	10	573	658	5	663
Ending Balance	$ 7,455	$ 112	$ 7,567	$ 7,616	$ 88	$ 7,704

(a) For further information about this expense, see Note 8. We do not have any obligation, nor do we expect to pay any amounts related to this expense.

During each of the six month periods ended June 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 six months ended June 30, 2012, we issued 1,953,723 and 3,414,795, respectively, of our common units pursuant to our equity distribution agreement with UBS. We received net proceeds of $153 million and $277 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.

On March 14, 2012, we issued 87,162 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 approximately $7 million, determining the units' value based on the $83.87 closing market price of the common units on the New York Stock Exchange on March 14, 2012.

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—Acquisitions."

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 May 15, 2012, we paid a cash distribution of $1.20 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended March 31, 2012. KMR, our sole i-unitholder, received a distribution of 1,603,975 i-units from us on May 15, 2012, based on the $1.20 per unit distributed to our common unitholders on that date. The distributions were declared on April 18, 2012, payable to unitholders of record as of April 30, 2012.

On May 13, 2011, we paid a cash distribution of $1.14 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended March 31, 2011. KMR, our sole i-unitholder, received a distribution of 1,599,149 i-units from us on May 13, 2011, based on the $1.14 per unit distributed to our common unitholders on that date. The distributions were declared on April 20, 2011, payable to unitholders of record as of April 29, 2011.

Our general partner's incentive distribution that we paid in May 2012 and May 2011 (for the quarterly periods ended March 31, 2012 and 2011, respectively) was $319 million and $280 million, respectively. The increased incentive distribution to our general partner paid for the first quarter of 2012 over the incentive distribution paid for the first 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. These two incentive distributions were reduced from what they would have been, however, by waived incentive amounts equal to $6 million and $7 million, respectively, related to common units issued to finance our acquisition of KinderHawk Field Services LLC (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 July 2012, we issued 168,806 of our common units for the settlement of sales made on or before June 30, 2012 pursuant to our equity distribution agreement. We received net proceeds of $13 million from the issuance of these 168,806 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On July 18, 2012, we declared a cash distribution of $1.23 per unit for the quarterly period ended June 30, 2012. The distribution will be paid on August 14, 2012 to unitholders of record as of July 31, 2012. Our common unitholders and our Class B unitholder will receive cash. KMR will receive a distribution of 1,578,616 additional i-units based on the $1.23 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.015541) will be issued. This fraction was determined by dividing:

- $1.23, the cash amount distributed per common unit

by

- $79.145, the average of KMR's shares' closing market prices from July 13-26, 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.

5. 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 June 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	(20.6) million barrels
Natural gas fixed price	(31.4) billion cubic feet
Natural gas basis	(32.0) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas basis	14.4 billion cubic feet

As of June 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 June 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 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 June 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, 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.

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 June 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 June 30, 2012 and December 31, 2011 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		June 30, 2012	December 31, 2011	June 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	$ 109	$ 66	$ (29)	$ (116)
	Current-Assets held for Sale / Accrued other current liabilities	3	—	—	—
	Non-current-Fair value of derivative contracts	87	39	(6)	(39)
Subtotal		199	105	(35)	(155)
Interest rate swap agreements	Current-Fair value of derivative contracts	1	3	—	—
	Non-current-Fair value of derivative contracts	623	593	—	—
Subtotal		624	596	—	—
Total		823	701	(35)	(155)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	3	3	(2)	(5)
Total		3	3	(2)	(5)
Total derivatives		$ 826	$ 704	$ (37)	$ (160)

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, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of June 30, 2012 and December 31, 2011, this unamortized premium totaled $512 million and $483 million, respectively, and as of June 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 six months ended June 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(a)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2012	2011	2012	2011
Interest rate swap agreements	Interest expense	$ 194	$ 128	$ 81	$ 64
Total		$ 194	$ 128	$ 81	$ 64
Fixed rate debt	Interest expense	$ (194)	$ (128)	$ (81)	$ (64)
Total		$ (194)	$ (128)	$ (81)	$ (64)

(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 June 30,			Three Months Ended June 30,			Three Months Ended June 30,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contracts	$ 303	$ 165	Revenues-Natural gas sales	$ 2	$ —	Revenues-Natural gas sales	$ —	$ —
			Revenues-Product sales and other	(2)	(87)	Revenues-Product sales and other	—	(2)
			Gas purchases and other costs of sales	11	—	Gas purchases and other costs of sales	—	—
Total	$ 303	$ 165	Total	$ 11	$ (87)	Total	$ —	$ (2)
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contracts	$ 189	$ (98)	Revenues-Natural gas sales	$ 2	$ 1	Revenues-Natural gas sales	$ —	$ —
			Revenues-Product sales and other	(31)	(152)	Revenues-Product sales and other	(3)	2
			Gas purchases and other costs of sales	9	11	Gas purchases and other costs of sales	—	—
Total	$ 189	$ (98)	Total	$ (20)	$ (140)	Total	$ (3)	$ 2

(a) We expect to reclassify an approximate $83 million gain associated with energy commodity price risk management activities and included in our Partners' Capital as of June 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 six months ended June 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 June 30, 2012 was (in millions):

	Asset position
Interest rate swap agreements	$ 624
Energy commodity derivative contracts	202
Gross exposure	826
Netting agreement impact	(28)
Cash collateral held	(9)
Net exposure	$ 789

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 June 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 June 30, 2012 and December 31, 2011, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling $9 million and $10 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. As of June 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 $2 million of additional collateral.

6. 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 June 30, 2012 and December 31, 2011, 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 our counterparties, which are reported within "Accrued other current liabilities" in our accompanying consolidated balance sheets.

	Asset fair value measurements using			
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of June 30, 2012				
Energy commodity derivative contracts(a)	$ 202	$ 27	$ 153	$ 22
Interest rate swap agreements	$ 624	$ —	$ 624	$ —
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			
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of June 30, 2012				
Energy commodity derivative contracts(a)	$ (37)	$ (9)	$ (26)	$ (2)
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 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 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 six months ended June 30, 2012 and 2011 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Derivatives-net asset (liability)				
Beginning of Period	$ (3)	(3)	$ 7	$ 19
Transfers out of Level 3	—	—	—	—
Total gains or (losses):				
Included in earnings	(2)	3	—	3
Included in other comprehensive income	28	7	6	(16)
Purchases	—	—	3	5
Settlements	(3)	—	4	(4)
End of Period	$ 20	7	$ 20	$ 7
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	$ (2)	$ (4)	$ (1)	$ 1

As of June 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 price at which the option was 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 June 30, 2012, this volatility ranged from 29% – 32% 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 June 30, 2012 and December 31, 2011 (both short-term and long-term, but excluding our debt fair value adjustments), is disclosed below (in millions):

	June 30, 2012		December 31, 2011	
	Carrying Value	**Estimated Fair value**	**Carrying Value**	**Estimated Fair value**
Total debt	$ 13,133	$ 14,717	$ 12,797	$ 14,238

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

7. 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;
- CO_2—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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Revenues				
Products Pipelines				
Revenues from external customers	$ 331	$ 228	$ 554	$ 453
Natural Gas Pipelines				
Revenues from external customers	693	963	1,487	1,906
CO_2				
Revenues from external customers	413	350	830	691
Terminals				
Revenues from external customers	342	320	683	652
Intersegment revenues	1	—	1	—
Kinder Morgan Canada				
Revenues from external customers	73	77	146	153
Total segment revenues	1,853	1,938	$ 3,701	3,855
Less: Total intersegment revenues	(1)	—	(1)	—
Total consolidated revenues	$ 1,852	$ 1,938	$ 3,700	$ 3,855

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 166	$ 21	$ 342	$ 201
Natural Gas Pipelines	190	135	412	301
CO_2	327	266	661	528
Terminals	195	171	382	345
Kinder Morgan Canada	52	54	102	102
Total segment earnings before DD&A	$ 930	647	$ 1,899	1,477
Total segment depreciation, depletion and amortization	(248)	(223)	(487)	(438)
Total segment amortization of excess cost of investments	(2)	(2)	(4)	(3)
General and administrative expenses(c)	(98)	(98)	(205)	(287)
Interest expense, net of unallocable interest income	(141)	(129)	(280)	(261)
Unallocable income tax expense	(3)	(3)	(5)	(5)
Income (Loss) from discontinued operations(d)	(279)	40	(551)	90
Total consolidated net income	$ 159	$ 232	$ 367	$ 573

	June 30, 2012	December 31, 2011
Assets		
Products Pipelines	$ 4,717	$ 4,479
Natural Gas Pipelines	7,527	9,958
CO_2	2,334	2,147
Terminals	4,662	4,428
Kinder Morgan Canada	1,803	1,827
Total segment assets	21,043	22,839
Corporate assets(e)	1,433	1,264
Assets held for sale(f)	1,938	—
Total consolidated assets	$ 24,414	$ 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 six month 2011 amounts include a $165 million increase in expense associated with rate case liability adjustments.

(c) Six 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.

(d) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. Three and six month 2012 amounts include loss amounts of $327 million and $649 million, respectively, from the remeasurement of net assets to fair value.

(e) 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.

(f) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

8. 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 June 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 June 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 June 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 $111 million and $112 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

Other Receivables and Payables

As of June 30, 2012 and December 31, 2011, our related party receivables (other than the notes receivable discussed above in "—Notes Receivable") totaled $30 million and $26 million, respectively. The June 30, 2012 receivables amount consisted of (i) $28 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 $28 million receivable amount consisted primarily of amounts due from KMI 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 both June 30, 2012 and December 31, 2011, our related party payables totaled $1 million, and we included these amounts within "Accounts payable" on our accompanying consolidated balance sheets. At each balance sheet date, our related party payables consisted of 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; 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 $734 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.

Non-Cash Compensation Expenses

In the first six 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.

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 June 30, 2012. 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 our affiliates.

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 June 30, 2012 and December 31, 2011 (in millions):

Derivatives – asset/(liability)	**June 30, 2012**	**December 31, 2011**
Current assets	$ 17	$ 9
Noncurrent assets	$ 28	$ 18
Current liabilities	$ (14)	$ (64)
Noncurrent liabilities	$ (3)	$ (10)

For more information on our risk management activities see Note 5.

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.

9. 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 six months ended June 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 six months ended June 30, 2012, and a description of any material events occurring subsequent to June 30, 2012, but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calnev Pipe Line LLC as Calnev; 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 Kinder Morgan CO_2 Company, L.P. (the successor to Shell CO_2 Company, Ltd.) as Kinder Morgan CO_2; 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; 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. Certain shippers and SFPP filed petitions at the D.C. Circuit for review of Opinion Nos. 511 and 511-A; these petitions are held in abeyance pending a ruling on SFPP's request for rehearing. It is not possible to predict the outcome of the 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: 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 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 No. IS12-390 (SFPP East Line Index Rates)—Protestants: Chevron, HollyFrontier, Phillips 66, Southwest Airlines, US Airways, Valero Marketing, and Western Refining—Status: These shippers protested SFPP's index-based rate increases for its East Line. FERC rejected the protests. Shippers may file requests for rehearing, and it is not possible to predict the outcome of further FERC review, if any;

- FERC Docket No. 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 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 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 April 6, 2010, a CPUC administrative law judge issued a proposed decision (Long case) 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 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. On March 13, 2012, the CPUC issued its decision on the Long case. The decision largely reflected the determinations made on April 6, 2010, 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, seeking a court order vacating the CPUC's determination that SFPP is not entitled to recover an income tax allowance in its intrastate rates. Court review remains pending.

On April 6, 2012, in proceedings unrelated to the above-referenced CPUC dockets, a CPUC administrative law judge issued a proposed decision (Bemesderfer case) 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.

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 CO_2. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO_2 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 CO_2 protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO_2 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 CO_2, 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 CO_2'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 CO_2 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 CO_2'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 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 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 June 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 $280 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, he 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 are now considering filing appeals to the New Jersey Supreme Court. 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. Kinder Morgan has executed a Combined Complaint and Consent Agreements, including monetary penalties of $158,000 for each plant to resolve these issues, and is awaiting final, executed settlement documents from the U.S. EPA.

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 October 2012. 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.

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, and we are in settlement discussions with ExxonMobil and Plains. 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 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 August and September 2012. 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 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, Kinder Morgan Inc., 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), Kinder Morgan, Inc., 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.

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 June 30, 2012, we have accrued an environmental reserve of $71 million (including $1 million of environmental related liabilities belonging to our FTC Natural Gas Pipelines disposal group). In addition, as of June 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.

10. 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 June 30, 2012 and December 31, 2011 are not material to our consolidated balance sheets.

For information on our pipeline regulatory proceedings, see Note 9 “Litigation, Environmental and Other Contingencies—Federal Energy Regulatory Commission Proceedings” and “California Public Utilities Commission Proceedings.”

11. 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 effect of ASU No. 2011-11.

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 and these statements include 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. For more information about our discontinued operations, see Notes 1 and 2 to our consolidated financial statements included elsewhere in this report.

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 June 30, 2012	Three Months Ended June 30, 2011	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 166	$ 21	$ 145	690%
Natural Gas Pipelines	190	135	55	41%
CO_2(c)	327	266	61	23%
Terminals(d)	195	171	24	14%
Kinder Morgan Canada(e)	52	54	(2)	(4)%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	930	647	283	44%
Depreciation, depletion and amortization expense	(248)	(223)	(25)	(11)%
Amortization of excess cost of equity investments	(2)	(2)	—	—%
General and administrative expense(f)	(98)	(98)	—	—%
Interest expense, net of unallocable interest income	(141)	(129)	(12)	(9)%
Unallocable income tax expense	(3)	(3)	—	—%
Income from continuing operations	438	192	246	128%
Income (Loss) from discontinued operations(g)	(279)	40	(319)	(798)%
Net Income	159	232	(73)	(31)%
Net (Income) Loss attributable to noncontrolling interests(h)	(6)	(2)	(4)	(200)%
Net Income (Loss) attributable to Kinder Morgan Energy Partners, L.P.	153	$ 230	(77)	(33)%

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Earnings increase / (decrease)	
	(In millions, except percentages)			
Segment earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 342	$ 201	$ 141	70%
Natural Gas Pipelines	412	301	111	37%
CO_2(i)	661	528	133	25%
Terminals(j)	382	345	37	11%
Kinder Morgan Canada(e)	102	102	—	—%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,899	1,477	422	29%
Depreciation, depletion and amortization expense	(487)	(438)	(49)	(11)%
Amortization of excess cost of equity investments	(4)	(3)	(1)	(33)%
General and administrative expense(k)	(205)	(287)	82	29%
Interest expense, net of unallocable interest income	(280)	(261)	(19)	(7)%
Unallocable income tax expense	(5)	(5)	—	—%
Income from continuing operations	918	483	435	90%
Income (Loss) from discontinued operations(l)	(551)	90	(641)	(712)%
Net Income	367	573	(206)	(36)%
Net (Income) Loss attributable to noncontrolling interests(m)	(8)	(5)	(3)	(60)%
Net Income (Loss) attributable to Kinder Morgan Energy Partners, L.P.	$ 359	$ 568	$ (209)	(37)%

(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 a $165 million increase in expense associated with rate case liability adjustments and an $11 million increase in income from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land, located in San Pedro, California.

(c) 2012 amount includes a $7 million gain from the sale of our ownership interest in the Claytonville oil field unit. 2011 amount includes a $2 million decrease in income from unrealized gains and losses on derivative contracts used to hedge forecast crude oil sales.

(d) 2012 amount includes a $12 million casualty indemnification gain related to a 2010 casualty at our Port Sulphur, Louisiana, International Marine Terminal facility. 2011 amount includes (i) a $4 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) a $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.; and (iii) a $1 million increase in expense associated with environmental liability adjustments.

(e) 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).

(f) 2011 amount includes a $2 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.

(g) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount consists of a $279 million loss before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (including a $327 million non-cash loss from remeasurements of net assets to fair value). 2011 amount consists of (i) $46 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) $6 million of depreciation and amortization expense.

(h) 2012 and 2011 amounts include increases of $1 million and decreases of $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.

(i) 2012 and 2011 amounts include a $3 million decrease in income and a $2 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.

(j) 2012 amount includes a $12 million casualty indemnification gain related to a 2010 casualty at our Port Sulphur, Louisiana, International Marine Terminal facility. 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 $2 million increase in income from adjustments associated with the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009; (iv) a $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 $2 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses; (vi) a $1 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal; and (vii) a $1 million increase in expense associated with environmental liability adjustments.

(k) 2012 amount includes a $1 million increase in unallocated severance expense associated with certain Terminal operations. 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 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 (iii) a $1 million increase in expense for certain asset and business acquisition costs.

(l) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount consists of (i) a $544 million loss before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (including a $649 million non-cash loss from remeasurements of net assets to fair value); and (ii) $7 million of depreciation and amortization expense. 2011 amount consists of (i) $103 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) $13 million of depreciation and amortization expense.

(m) 2012 and 2011 amounts include decreases of $2 million and $4 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the six month 2012 and 2011 items previously disclosed in these footnotes.

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.

For the comparable second quarter periods of 2012 and 2011, our total segment earnings before depreciation, depletion and amortization expenses increased $283 million (44%) in 2012; however, this overall increase in earnings:

- included a $168 million increase in earnings before depreciation, depletion and amortization 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 $19 million in the second quarter of 2012 and decrease segment EBDA by $149 million in the second quarter of 2011); and

- excluded an $8 million decrease in earnings before depreciation, depletion and amortization expenses from discontinued operations (as described in footnote (g) to the table above and excluding both the $327 million non-cash loss from the remeasurement of net assets to fair value in the second quarter of 2012 and the $10 million increase in expense in the second 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 $107 million (13%) increase in quarterly segment earnings before depreciation, depletion and amortization resulted from better performance in the second quarter of 2012 from our CO_2, Natural Gas Pipelines, and Terminals business segments, partially offset by lower earnings from our Products Pipelines business segment.

For the comparable six month periods, total segment earnings before depreciation, depletion and amortization expenses increased $422 million (29%) in 2012; however, this overall increase:

- included a $157 million increase in earnings before depreciation, depletion and amortization from the effect of the certain items described in footnotes (b), (e), (i), and (j) to the table above (which combined to increase total segment EBDA by $16 million in the first six months of 2012 and decrease segment EBDA by $141 million in the first six months of 2011); and

- excluded an $8 million decrease in earnings before depreciation, depletion and amortization expenses from discontinued operations (as described in footnote (l) to the table above and excluding both the $649 million non-cash loss from the remeasurement of net assets to fair value in the first six months of 2012 and the $10 million increase in expense in the second 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 $257 million (15%) increase in segment earnings before depreciation, depletion and amortization in the first half of 2012 versus the first half of 2011 resulted from higher earnings from our CO_2, Natural Gas Pipelines, Terminals, and Kinder Morgan Canada business segments, partially offset by lower earnings from our Products Pipelines business segment.

Products Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions, except operating statistics)			
Revenues	$ 331	$ 228	$ 554	$ 453
Operating expenses(a)	(184)	(228)	(241)	(280)
Other income(b)	—	11	—	11
Earnings from equity investments	15	12	29	23
Interest income and Other, net	8	2	10	3
Income tax (expense) benefit	(4)	(4)	(10)	(9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 166	$ 21	$ 342	$ 201
Gasoline (MMBbl)(c)	99.7	99.6	194.8	195.5
Diesel fuel (MMBbl)	35.8	36.9	69.4	73.5
Jet fuel (MMBbl)	28.8	29.2	55.7	54.8
Total refined product volumes (MMBbl)	164.3	165.7	319.9	323.8
Natural gas liquids (MMBbl)	7.2	5.6	14.6	12.2
Total delivery volumes (MMBbl)(d)	171.5	171.3	334.5	336.0
Ethanol (MMBbl)(e)	7.8	7.7	15.1	15.0

(a) Three and six month 2011 amounts include a $165 million increase in expense associated with rate case liability adjustments.

(b) Three and six month 2011 amounts represent an $11 million increase in income from the disposal of property related to the sale of a portion of our former Gaffey Street terminal land, located in San Pedro, California.

(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.

The certain items described in footnotes (a) and (b) to the table above increased our Product Pipelines' earnings before depreciation, depletion and amortization expenses by $154 million in both the second quarter and first six months of 2012, when compared to the same two periods of 2011. Following is information, for each of the comparable three and six month periods of 2012 and 2011, related to the segment's (i) remaining $9 million (5%) and $13 million (4%) decreases in earnings before depreciation, depletion and amortization; and (ii) $103 million (45%) and $101 million (22%) increases in operating revenues:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Transmix operations	$ (13)	(151)%	$ 108	842%
Pacific operations	(8)	(10)%	(7)	(6)%
Cochin Pipeline	10	137%	2	19%
Plantation Pipeline	2	16%	—	—%
All others (including eliminations)	—	—%	—	—%
Total Products Pipelines	$ (9)	(5)%	$ 103	45%

Six months ended June 30, 2012 versus Six months ended June 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ (16)	(10)%	$ (10)	(5)%
Transmix operations	(14)	(80)%	107	427%
Cochin Pipeline	10	41%	2	7%
Plantation Pipeline	4	14%	1	6%
All others (including eliminations)	3	3%	1	1%
Total Products Pipelines	$ (13)	(4)%	$ 101	22%

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

- decreases of $13 million (151%) and $14 million (80%), respectively, from our transmix processing operations—due primarily to lower earnings in the second quarter of 2012. The quarter-to-quarter decrease in earnings was driven by both an $8 million drop in gross margin (due mainly to an 18% decrease in processing volumes) and a $4 million decrease due to unfavorable net carrying value adjustments to product inventory. The period-to-period increases in revenues were due mainly to the expiration of certain transmix processing agreements in March 2012. The expiring contracts provided for transmix processing at certain of our facilities to be performed by us for third parties under a "for fee" basis. Due to the expiration of these contracts and our assumption of additional marketing rights, 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;

- decreases of $8 million (10%) and $16 million (10%), respectively, from our Pacific operations—driven primarily by lower mainline transportation revenues resulting from lower average FERC tariffs as a result of rate case rulings settlements made since the end of the second quarter of 2011; and for the comparable six month periods, by higher operating expenses related to certain rights-of-way obligations and legal matters;

- increases of $10 million (137%) and $10 million (41%), respectively, from our Cochin Pipeline—chiefly due to higher revenues, due to an 87% increase in pipeline throughput volumes, and to higher non-operating other income from the favorable settlement of a pipeline access dispute; and

- increases of $2 million (16%) and $4 million (14%), respectively, from our approximate 51% interest in the Plantation pipeline system—due primarily to higher average tariff rates since the end of the second quarter of 2011.

Natural Gas Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions, except operating statistics)			
Revenues	$ 693	$ 963	$ 1,487	$ 1,906
Operating expenses	(543)	(864)	(1,151)	(1,669)
Earnings from equity investments	39	37	77	66
Interest income and Other, net	1	1	1	1
Income tax (expense) benefit	—	(2)	(2)	(3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments from continuing operations	190	135	412	301
Discontinued operations(a)	(279)	46	(544)	103
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments including discontinued operations	$ (89)	$ 181	$ (132)	$ 404
Natural gas transport volumes (Bcf)(b)	795.3	749.9	1,531.3	1,457.6
Natural gas sales volumes (Bcf)(c)	215.6	192.4	428.4	383.6

(a) Represents earnings (losses) before depreciation, depletion and amortization expense attributable to our FTC Natural Gas Pipelines disposal group. Three and six month 2012 amounts include non-cash losses of $327 million and $649 million, respectively, from remeasurements of the FTC Natural Gas Pipelines disposal group to fair value. Three and six month 2011 amounts include a $10 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. Three and six month 2012 amounts also include revenues of $62 million and $133 million, respectively, and three and six month 2011 amounts also include revenues of $82 million and $158 million, respectively.

(b) Includes TransColorado Gas Transmission Company LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC, Fayetteville Express Pipeline LLC and Texas intrastate natural gas pipeline group pipeline volumes.

(c) Represents Texas intrastate natural gas pipeline group volumes.

When compared to the same two periods of 2011, the certain items described in footnote (a) to the table above decreased our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization (including discontinued operations) by $317 million and $639 million, respectively, in the second quarter and first six months of 2012. Following is information, for each of the comparable three and six month periods of 2012 and 2011 and including discontinued operations, related to the increases and decreases in the segment's (i) remaining $47 million (25%) and $103 million (25%) increases in earnings before depreciation, depletion and amortization; and (ii) $290 million (28%) and $444 million (22%) decreases in operating revenues:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 31	246%	$ 50	n/a
Kinder Morgan Treating operations	11	99%	27	170%
Fayetteville Express Pipeline(b)	9	171%	n/a	n/a
Eagle Ford Gathering(b)	4	n/a	n/a	n/a
EagleHawk Field Services(b)	2	n/a	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	(2)	(4)%	(347)	(38)%
All others (including eliminations)	—	—%	—	—%
Total Natural Gas Pipelines-continuing operations	$ 55	41%	$ (270)	(28)%
Discontinued operations(c)	(8)	(14)%	(20)	(25)%
Total Natural Gas Pipelines-including discontinued operations	$ 47	25%	$ (290)	(28)%

Six months ended June 30, 2012 versus Six months ended June 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 66	296%	$ 101	n/a
Fayetteville Express Pipeline(b)	21	371%	n/a	n/a
Kinder Morgan Treating operations	18	84%	44	137%
Eagle Ford Gathering(b)	6	n/a	n/a	n/a
EagleHawk Field Services(b)	5	n/a	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	(7)	(4)%	(564)	(31)%
All others (including eliminations)	2	2%	—	—%
Total Natural Gas Pipelines-continuing operations	$ 111	37%	$ (419)	(22)%
Discontinued operations(c)	(8)	(7)%	(25)	(16)%
Total Natural Gas Pipelines-including discontinued operations	$ 103	25%	$ (444)	(22)%

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

- increases of $31 million (246%) and $66 million (296%), respectively, attributable to incremental earnings from our now wholly-owned KinderHawk Field Services LLC. Effective July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk that we did not already own, and subsequently, began accounting for our investment under the full consolidation method;

- increases of $11 million (99%) and $18 million (84%), respectively, from our Kinder Morgan Treating operations—due mainly to incremental earnings from the natural gas treating operations we acquired from SouthTex Treaters, Inc. effective November 30, 2011;

- increases of $9 million (171%) and $21 million (371%), respectively, attributable to incremental equity earnings from our 50%-owned Fayetteville Express pipeline system—due to both higher firm contract transportation revenues and lower period-to-period interest expense. The higher revenues were driven by increases in natural gas transmission volumes of 8% and 19%, respectively (while full transportation service began January 1, 2011, contracts were still ramping up during the first half of 2011), and the decreases in interest expense related to Fayetteville's refinancing of its prior bank credit facility in July 2011;

- incremental equity earnings of $6 million and $11 million, respectively, from the combined operations of our 50%-owned Eagle Ford Gathering LLC and our 25%-owned EagleHawk Field Services LLC, both of which provide natural gas gathering, transportation and processing services in the Eagle Ford shale gas formation in South Texas. Eagle Ford Gathering initiated flow on its natural gas gathering system on August 1, 2011. We acquired our ownership interest in EagleHawk effective July 1, 2011; and

- earnings from our Texas intrastate natural gas pipeline group were essentially flat across both quarterly periods. The $7 million (4%) decrease in earnings in the first half of 2012 versus the first half of 2011 was due primarily to lower margins on both natural gas sales and processing activities (attributable to lower average sales prices and higher severance/royalties expenses, respectively), higher gas losses, and the timing of higher operating expenses. The overall decrease was partially offset, however, by higher transportation and storage margins (attributable to a 22% increase in transport volumes and higher storage spreads, respectively).

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three and six 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 second quarter periods of 2012 and 2011, our Texas intrastate natural gas pipeline group accounted for 75% and 88%, respectively, of the segment’s revenues, and 88% and 94%, respectively, of the segment’s operating expenses. For the comparable six month periods of both years, the intrastate group accounted for 77% and 88%, respectively, of total segment revenues, and 89% and 94%, respectively, of total segment operating expenses.

CO_2

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(In millions, except operating statistics)			
Revenues(a)	$ 413	$ 350	$ 830	$ 691
Operating expenses	(98)	(89)	(185)	(173)
Other income(b)	7	—	7	—
Earnings from equity investments	7	5	13	11
Interest income and Other, net	(1)	1	(1)	1
Income tax (expense) benefit	(1)	(1)	(3)	(2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 327	$ 266	$ 661	$ 528
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(c)	1.2	1.3	1.2	1.3
Southwest Colorado carbon dioxide production (net) (Bcf/d)(c)	0.5	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(d)	28.4	28.4	27.6	28.6
SACROC oil production (net)(MBbl/d)(e)	23.6	23.7	23.0	23.9
Yates oil production (gross)(MBbl/d)(d)	20.8	21.8	21.0	21.8
Yates oil production (net)(MBbl/d)(e)	9.2	9.7	9.3	9.7
Katz oil production (gross)(MBbl/d)(d)	1.8	0.3	1.6	0.2
Katz oil production (net)(MBbl/d)(e)	1.5	0.2	1.4	0.2
Natural gas liquids sales volumes (net)(MBbl/d)(e)	9.5	8.4	9.3	8.3
Realized weighted average oil price per Bbl(f)	85.96	69.37	$ 88.25	$ 69.07
Realized weighted average natural gas liquids price per Bbl(g)	49.44	66.67	$ 55.22	$ 63.83

(a) Six month 2012 amount includes unrealized losses of $3 million, and three and six month 2011 amounts include unrealized losses of $2 million and unrealized gains of $2 million, respectively, all relating to derivative contracts used to hedge forecast crude oil sales.

(b) Three and six month 2012 amounts represent 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 CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) 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 six months ended June 30, 2012, the certain items described in footnotes (a) and (b) to the table above (i) increased earnings before depreciation, depletion and amortization by $9 million and $2 million, respectively; and (ii) increased revenues by $2 million and decreased revenues by $5 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 six month periods of 2012 and 2011, in the segment's remaining (i) $52 million (19%) and $131 million (25%) increases in earnings before depreciation, depletion and amortization; and (ii) $61 million (17%) and $144 million (21%) increases in operating revenues:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 38	20%	$ 49	18%
Sales and Transportation Activities	14	17%	11	13%
Intrasegment eliminations	—	—%	1	6%
Total CO_2	$ 52	19%	$ 61	17%

Six months ended June 30, 2012 versus Six months ended June 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 105	28%	$ 118	22%
Sales and Transportation Activities	26	17%	22	13%
Intrasegment eliminations	—	—%	4	13%
Total CO_2	$ 131	25%	$ 144	21%

The period-to-period increases in earnings from the segment's oil and gas producing activities were driven by increases of $57 million (27%) and $120 million (28%), respectively, in crude oil sales revenues. The increases were due to both higher average realizations for U.S. crude oil and increased oil production at the Katz field unit. When compared to the same periods a year ago, our realized weighted average price per barrel of crude oil increased 24% in the second quarter of 2012 and 28% in the first six months of 2012. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $87.45 and $93.92 per barrel in the second quarter and first six months of 2012, respectively, and $99.83 and $95.29 per barrel in the second quarter and first six months of 2011, respectively. Partially offsetting the increases in crude oil sales revenues were decreases in plant product sales revenues of $8 million (16%) and $3 million (3%), respectively, due to period-to-period decreases in the realized weighted average price per barrel of natural gas liquids of 26% and 13%, respectively.

The increases in earnings before depreciation, depletion and amortization expenses from the segment's sales and transportation activities were primarily related to higher carbon dioxide sales revenues and higher non-consent revenues, relative to 2011. When compared to the same 2011 periods, carbon dioxide sales revenues increased by $9 million (14%) in the second quarter of 2012 and by $15 million (12%) in the first six months of 2012, driven by increases of 23% and 21%, respectively, in the average price received for all carbon dioxide sales. The higher average sales prices were due 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. The increases in non-consent revenues during 2012 related to sharing arrangements pertaining to certain expansion projects completed at the McElmo Dome unit in Colorado since the end of the second quarter of 2011.

Terminals

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions, except operating statistics)			
Revenues	$ 343	320	$ 684	$ 652
Operating expenses(a)	(164)	(156)	(324)	(324)
Other income(b)	13	3	13	3
Earnings from equity investments	5	3	11	5
Interest income and Other, net(c)	1	4	1	5
Income tax (expense) benefit(d)	(3)	(3)	(3)	4
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 195	$ 171	$ 382	$ 345
Bulk transload tonnage (MMtons)(e)	25.9	24.8	50.2	48.1
Ethanol (MMBbl)	16.3	13.6	34.2	29.3
Liquids leaseable capacity (MMBbl)	60.2	58.8	60.2	58.8
Liquids utilization %	93.0%	92.6%	93.0%	92.6%

(a) Three and six month 2011 amounts include a $1 million increase in expense at our Carteret, New Jersey liquids terminal associated with environmental liability adjustments. Six month 2011 amount also includes (i) a combined $2 million increase in expense at our Carteret terminal, associated with fire damage and repair activities, and the settlement of a certain litigation matter; and (ii) a $1 million increase in expense associated with the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009.

(b) Three and six month 2012 amounts include a $12 million casualty indemnification gain related to a 2010 casualty at our Port Sulphur, Louisiana, International Marine Terminal facility. Three and six month 2011 amounts include a $4 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal.

(c) Three and six month 2011 amounts include a $4 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.

(d) Three and six month 2011 amounts include 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). Six month 2011 amount also includes 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), and 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 fleeting business described in footnote (a).

(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 three and six months ended June 30, 2012, the certain items related to our Terminals business segment and described in the footnotes to the table above increased segment earnings before depreciation, depletion and amortization expenses by $7 million and $3 million, respectively, when compared to the same two periods of 2011.

Following is information related to the increases and decreases, in the comparable three and six month periods of 2012 and 2011, in the segment's remaining (i) $17 million (10%) and $34 million (10%) increases in earnings before depreciation, depletion and amortization; and (ii) $23 million (7%) and $32 million (5%) increases in operating revenues:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	$ 6	14%	$ 5	8%
Mid-Atlantic	4	26%	8	27%
Gulf Bulk	4	28%	3	9%
Northeast	3	17%	4	12%
Acquired assets and businesses	2	n/a	2	n/a
Rivers	(2)	(11)%	(2)	(6)%
All others (including intrasegment eliminations and unallocated income tax expenses)	—	—%	3	2%
Total Terminals	$ 17	10%	$ 23	7%

Six months ended June 30, 2012 versus Six months ended June 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic	$ 13	42%	$ 16	28%
Gulf Liquids	10	11%	10	8%
Acquired assets and businesses	6	n/a	4	n/a
Northeast	7	18%	10	14%
Gulf Bulk	6	24%	3	4%
Rivers	(6)	(16)%	(5)	(7)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(2)	(2)%	(6)	(2)%
Total Terminals	$ 34	10%	$ 32	5%

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 due to higher gasoline throughputs, higher ethanol volumes through our Deer Park, Texas rail terminal, and to higher warehousing revenues as a result of new and renewed customer agreements at higher rates. For all liquids facilities combined, we increased our liquids leasable capacity by 1.4 million barrels (2.4%) since the end of the second quarter of last year, primarily via completed terminal expansion projects.

The increases in earnings from our Mid-Atlantic region were driven by increases of $4 million and $11 million, respectively, from our Pier IX terminal, located in Newport News, Virginia. Pier IX's earnings increases were primarily due to higher export coal shipments, driven by growth in the coal export market. Including all terminals, coal transload tonnage increased by 1.1 million tons (12%) in the second quarter of 2012 and by 1.6 million tons (9%) in the first half of 2012, when compared to the same prior year periods.

We also benefitted from higher period-to-period earnings from (i) our Gulf Bulk terminals—due mainly to higher coal and petroleum coke handling and loading operations at our Deepwater terminal located on the Houston Ship Channel, and to higher coal and petroleum coke volumes at our Port of Houston and Port Arthur, Texas facilities, respectively; and (ii) our Carteret, New Jersey liquids terminal (Northeast region)—due primarily to higher transfer and storage rates and to tank expansion projects completed since the end of the second quarter of 2011.

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 (acquired in June 2011). The incremental amounts represent earnings and revenues from acquired terminals' operations during the additional month of ownership in the first six months of 2012, and do not include increases or decreases during the same months we owned the assets in 2011.

The combined earnings before depreciation, depletion and amortization from all of the terminal operations included in our Rivers region was essentially unchanged across both three month periods, but decreased $6 million (16%) in the first half of 2012, versus the first half of 2011. The decrease was driven by lower coal transload volumes in the first half of 2012 as a result of a drop in domestic demand, due mainly to lower natural gas prices, and the impact of unfavorable weather relative to the first half of 2011.

The quarter-to-quarter decrease in our Terminals segment's revenues—reported in the "All others" line in the table above—relates largely to terminal assets we sold (or contributed to joint ventures) and no longer consolidate since the end of the first quarter of 2011.

Kinder Morgan Canada

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions, except operating statistics)			
Revenues	$ 73	$ 77	$ 146	$ 153
Operating expenses	(23)	(24)	(47)	(50)
Earnings (losses) from equity investments	1	(1)	2	(2)
Interest income and Other, net	4	4	7	7
Income tax (expense) benefit(a)	(3)	(2)	(6)	(6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 52	$ 54	$ 102	$ 102
Transport volumes (MMBbl)(b)	26.9	22.9	51.8	49.6

(a) Three and six month 2011 amounts include 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. For the comparable three and six month periods, 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 both the second quarter and first six months of 2012, when compared to the same two periods last year. For each of the segment's three primary businesses, following is information for (i) the remaining $2 million (2%) increase in earnings before depreciation, depletion and amortization in the first six months of 2012 versus the first six months of 2011; and (ii) the $4 million (5%) and $7 million (5%) decreases in operating revenues, respectively, for each of the comparable three and six month periods of 2012 and 2011:

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

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Express Pipeline(a)	$ 2	72%	n/a	n/a
Trans Mountain Pipeline	(2)	(3)%	$ (4)	(5)%
Jet Fuel Pipeline	—	—%	—	—%
Total Kinder Morgan Canada	$ —	—%	$ (4)	(5)%

Six months ended June 30, 2012 versus Six months ended June 30, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Express Pipeline(a)	$ 3	60%	n/a	n/a
Trans Mountain Pipeline	(1)	(1)%	$ (7)	(4)%
Jet Fuel Pipeline	—	—%	—	—%
Total Kinder Morgan Canada	$ 2	2%	$ (7)	(5)%

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

Our Kinder Morgan Canada segment's earnings before depreciation, depletion and amortization expenses were essentially flat across both comparable three and six month periods. The slight period-to-period increases in earnings from our equity investment in the Express pipeline system were mainly due to higher domestic volumes on Express' Platte Pipeline segment. The slight decreases in Trans Mountain's earnings were due mainly to the impacts of unfavorable currency translation, due to the weakening, in 2012, of the Canadian dollar relative to the U.S. dollar in both comparable three and six month periods.

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In millions)			
General and administrative expenses(a)	$ 98	$ 98	$ 205	$ 287
Interest expense, net of unallocable interest income	$ 141	$ 129	$ 280	$ 261
Unallocable income tax expense	$ 3	$ 3	$ 5	$ 5
Net income attributable to noncontrolling interests(b)	$ 6	$ 2	$ 8	$ 5

(a) Six month 2012 amount includes a $1 million increase in unallocated severance expense associated with certain Terminal operations. Three and six month 2011 amounts include a $2 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. Six month 2011 amount also 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 expense; and (ii) a $1 million increase in expense for certain asset and business acquisition costs.

(b) Three and six month 2012 amounts include increases of $1 million and decreases of $2 million, respectively, in net income attributable to our noncontrolling interests, and the three and six month 2011 amounts include decreases of $3 million and $4 million, respectively, in net income attributable to our noncontrolling interests, all related to the combined effect of the three and six 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 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.

Compared with the same quarter of 2011, our general and administrative expenses were essentially flat in the second quarter of 2012. For the comparable six month periods, the certain items described in footnote (a) to the table above accounted for a $92 million decrease in expense in 2012 versus 2011. The remaining $10 million (5%) period-to-period increase in expense included increases and decreases in various operational expenses, but consisted primarily of higher benefit and payroll tax expenses and higher employee labor expenses. These increases were driven by cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force.

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. Our net interest expense increased $12 million (9%) in the second quarter of 2012 and $19 million (7%) in the first six months of 2012, when compared with the same prior year periods. The increases were due to higher average debt balances in 2012 (average borrowings for both comparable three and six month periods increased 13% in 2012 compared to 2011), largely due to the capital expenditures, business acquisitions, and joint venture contributions we have made since the end of the second quarter of 2011. The increases in net interest expense were slightly offset, however, by lower weighted average interest rates. The weighted average interest rate on all of our borrowings—including both short-term and long-term amounts—was essentially flat across both three month periods (from 4.29% for the second quarter of 2011 to 4.27% for the second quarter of 2012), and dropped 3% in the first half of 2012 versus the first half of 2011 (from 4.36% for the first half of 2011 to 4.25% for the first half 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 June 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 5 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of June 30, 2012, we had $522 million of "Cash and cash equivalents" on our consolidated balance sheet (included elsewhere in this report), an increase of $113 million (28%) from December 31, 2011. We also had, as of June 30, 2012, approximately $1.5 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

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. On July 17, 2012, Moody's changed its outlook for us from negative to stable. 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.

Short-term Liquidity

As of June 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 $2.2 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 (discussed below in "—Operating Activities"). 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 June 30, 2012, our credit facility was not drawn on.

Our outstanding short-term debt as of June 30, 2012 was $979 million, primarily consisting of $500 million in principal amount of 5.85% senior notes that mature September 15, 2012, and $446 million of outstanding commercial paper borrowings. 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. As of December 31, 2011, our short-term debt totaled $1,638 million.

We had a working capital surplus of $1,196 million as of June 30, 2012 and a working capital deficit of $1,543 million as of December 31, 2011. The overall $2,739 million (178%) favorable change from year-end 2011 was primarily due to (i) our reclassification of the June 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 third 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 June 30, 2012); and (ii) an increase in working capital due to a decrease 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 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 about our equity issuances in the first half of 2012, see Note 4 "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.

As of June 30, 2012 and December 31, 2011, the net carrying value of the various series of our senior notes was $12,575 million and $12,026 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $112 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 six months of 2012, see Note 3 "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 six month periods of 2012 and 2011, our sustaining capital expenditures totaled $96 million and $85 million, respectively. These amounts included $5 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; and (viii) 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 $304 million for sustaining capital expenditures for the full year 2012. This amount (i) includes expenditures associated with the assets we expect to acquire from KMI in the third quarter of 2012 for the months of our ownership (discussed below in "—Additional Capital Requirements"); and (ii) excludes expenditures associated with the assets in our FTC Natural Gas Pipelines disposal group for the months after 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.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. Our discretionary capital expenditures totaled $686 million in the first half of 2012, and $453 million in the first half of 2011. The period-to-period increase in discretionary capital expenditures was primarily due to higher investment undertaken in the first half of 2012 to expand and improve our Terminals and Products Pipelines business segments. Generally, we initially fund our discretionary capital expenditures through borrowings under our commercial paper program or our revolving credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

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. In the second quarter of 2012, we confirmed binding commercial support for this expansion project, which includes (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. 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 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. Currently, we expect KMI to offer to sell (drop-down) all of the Tennessee Gas Pipeline system and a 50% ownership interest in the El Paso Natural Gas pipeline system to us in order to replace the assets that we will divest (our FTC Natural Gas Pipelines disposal group). We expect that these asset drop-downs and the divestitures (discussed in Note 1 "General—Kinder Morgan, Inc. and Kinder Morgan G.P., Inc." to our consolidated financial statements included elsewhere in this report) will close in the third quarter of 2012. Excluding amounts for the assets we expect to acquire 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 $1,504 million for the six months ended June 30, 2012, versus $1,239 million in the same comparable period of 2011. The period-to-period increase of $265 million (21%) in cash flow from operations primarily consisted of the following:

- a $199 million increase in cash from overall higher partnership income—after adjusting our period-to-period $206 million decrease in net income for the following five non-cash items: (i) a $649 million increase from the non-cash loss on remeasurement of our FTC Natural Gas Pipelines disposal group to fair value (discussed further in Note 2 to our consolidated financial statements included elsewhere in this report); (ii) a $44 million increase due to higher non-cash depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); (iii) a $165 million decrease related to rate case reserve adjustments that increased expense in June 2011; (iv) a $90 million decrease due to certain higher non-cash compensation expenses allocated to us from KMI in the first half of 2011 (as discussed in Note 8 "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 (v) a $33 million decrease due to higher earnings from equity investees in the first half 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);

- a $72 million increase in cash due to lower volumes and costs of natural gas put into storage on our Kinder Morgan Texas Pipeline system;

- a $53 million increase in cash from an interest rate swap termination payment received in June 2012, when we terminated a fixed-to-variable interest rate swap agreement having a notional principal amount of $100 million; and

- an $89 million decrease in cash due to higher products inventory, primarily due to incremental expenditures for short-term liquids transmix inventories.

Investing Activities

Net cash used in investing activities was $814 million for the six month period ended June 30, 2012, compared to $517 million used in the comparable 2011 period (our acquisition of a 50% ownership interest in El Paso Midstream Investment Company, LLC in June 2012 for an aggregate consideration of $289 million in common units 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). The overall $297 million (57%) decrease in cash from investing activities primarily consisted of the following:

- a $242 million decrease in cash due to higher capital expenditures, as described above in "—Capital Expenditures;"

- a $50 million decrease in cash related to net changes in margin and restricted deposits, due to the January 2011 release of $50 million in cash previously restricted for our investment in Watco (described below);

- a $35 million decrease in cash due to lower capital distributions (distributions in excess of cumulative earnings) received from equity investments in the first half of 2012—chiefly due to decreases in capital distributions received from both Rockies Express Pipeline LLC and KinderHawk Field Services LLC. However, (i) the decrease in distributions of capital from Rockies Express was partially offset by higher distributions of earnings, which are included within the Operating Activities section of our consolidated statement of cash flows; and (ii) the decrease in distributions of capital received from KinderHawk was due to the fact that we held only a 50% ownership interest in KinderHawk during the first half of 2011 and we accounted for our investment under the equity method of accounting; and

- an $80 million increase in cash due to lower expenditures for acquisitions of assets and investments. In the first six months of 2012, we paid $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. In the first half of 2011, we spent a combined $110 million for asset and investment acquisitions, including $50 million for an initial preferred equity interest in Watco Companies, LLC, and $43 million for a newly constructed petroleum coke terminal located in Port Arthur, Texas.

Financing Activities

Net cash used in financing activities amounted to $575 million for the first half of 2012, and $501 million for the first half of 2011. The $74 million (15%) overall decrease in cash due to higher cash expended for financing activities consisted of the following:

- a $429 million decrease in cash due to lower partnership equity issuances. The decrease reflects the $277 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first six months of 2012 (discussed in Note 4 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report), versus the $706 million we received from the sales of additional common units in the first six months a year ago. In both six month periods, we used the proceeds from our equity issuances to reduce the borrowings under our commercial paper program;

- a $123 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 $1,209 million in the first six months of 2012. In the same comparable period of 2011, we distributed $1,086 million to our partners. Further information regarding our distributions is discussed following in "—Partnership Distributions;" and

- a $474 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The increase in cash consisted of (i) a $323 million increase due to lower net repayments of short-term borrowings under our commercial paper program; and (ii) a combined $151 million increase due to higher net issuances of our senior notes (in the first six months of 2012 and 2011, we generated net proceeds of $544 million and $393 million, respectively, from both issuing and repaying senior notes).

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 second quarters of 2012 and 2011 (for the first quarterly periods of 2012 and 2011, respectively), see Note 4 "Partners' Capital—Income Allocation and Declared Distributions" to our consolidated financial statements included elsewhere in this report.

Furthermore, on July 18, 2012, we declared a cash distribution of $1.23 per unit for the second quarter of 2012 (an annualized rate of $4.92 per unit). This distribution is 7% higher than the $1.15 per unit distribution we made for the second quarter of 2011. Our declared distribution for the second quarter of 2012 of $1.23 per unit will result in an incentive distribution to our general partner of $337 million (including the effect of a waived incentive distribution amount of $7 million related to our KinderHawk acquisition). Comparatively, our distribution of $1.15 per unit paid on August 12, 2011 for the second quarter of 2011 resulted in an incentive distribution payment to our general partner in the amount of $293 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 second quarter of 2012 over the incentive distribution for the second quarter of 2011 reflects the increase in the distribution per unit as well as the issuance of additional units. For additional information about our second quarter 2012 cash distribution, see Note 4 "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 drop-downs from KMI (discussed in Note 1 “General—Kinder Morgan, Inc. and Kinder Morgan G.P., Inc.” 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 CO_2 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 $93.05 per barrel in 2012.

Furthermore, for 2012, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 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. We also currently expect to be unfavorably impacted by lower natural gas liquids prices, which we now project to be approximately 23% lower for the full year 2012 than was assumed when we developed our 2012 budget. Due to the deteriorating natural gas liquids prices, we now expect to generate distributable cash flow in 2012 essentially equivalent to our distributions for 2012.

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 11 “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” 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 5 “Risk Management” to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of June 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 June 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 9 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.

The terms upon which we will sell the assets comprising our FTC Natural Gas Pipelines disposal group are uncertain.

As a condition to receiving antitrust approval from the FTC of KMI's acquisition of El Paso, KMI has agreed to divest the assets comprising our FTC Natural Gas Pipelines disposal group within six months following its acquisition of El Paso. As a result, the price at which we ultimately agree to sell these assets may be less than the price at which we would otherwise expect to sell them.

Further, as a result of this agreement with the FTC, in the first six months of 2012, we reduced the disposal group's net asset carrying value to its estimated fair value and recognized a $649 million loss on the remeasurement to fair value. However, the terms upon which we will sell these assets are subject to negotiation and agreement with an as-yet undetermined third party. As a result, our estimate of the fair value of the disposal group's net assets may not reflect the price at which we ultimately agree to sell them.

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 June 4, 2012, we issued 3,792,461 common units as the purchase price for a 50% equity ownership interest in El Paso Midstream Investment Company, LLC that we acquired from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. The acquisition was made effective June 1, 2012. 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.

4.1 —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.

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 six months ended June 30, 2012 and 2011; (ii) our Consolidated Statements of Comprehensive Income for the three and six months ended June 30, 2012 and 2011; (iii) our Consolidated Balance Sheets as of June 30, 2012 and December 31, 2011; (iv) our Consolidated Statements of Cash Flows for the six months ended June 30, 2012 and 2011; and (v) the notes to our Consolidated Financial Statements.

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: July 27, 2012

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