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 **March 31, 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 234,383,015 common units outstanding as of April 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 March 31, 2012	Three Months Ended March 31, 2011
Revenues		
Natural gas sales	$ 584	$ 803
Services	761	741
Product sales and other	503	373
Total Revenues	1,848	1,917
Operating Costs, Expenses and Other		
Gas purchases and other costs of sales	580	793
Operations and maintenance	306	296
Depreciation, depletion and amortization	239	215
General and administrative	107	189
Taxes, other than income taxes	50	46
Total Operating Costs, Expenses and Other	1,282	1,539
Operating Income	566	378
Other Income (Expense)		
Earnings from equity investments	65	47
Amortization of excess cost of equity investments	(2)	(1)
Interest expense	(140)	(132)
Interest income	5	4
Other, net	1	1
Total Other Income (Expense)	(71)	(81)
Income from Continuing Operations Before Income Taxes	495	297
Income Tax (Expense) Benefit	(15)	(6)
Income from Continuing Operations	480	291
Discontinued Operations (Note 2)		
Income from operations of FTC Natural Gas Pipelines disposal group	50	50
Loss on remeasurement of FTC Natural Gas Pipelines disposal group to fair value	(322)	-
(Loss) Income from Discontinued Operations	(272)	50
Net Income	208	341
Net Income Attributable to Noncontrolling Interests	(2)	(3)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 206	$ 338
Calculation of Limited Partners' Interest in Net Income (Loss) Attributable to Kinder Morgan Energy Partners, L.P.:		
Income from Continuing Operations	$ 475	$ 288
Less: General Partner's Interest	(321)	(280)
Limited Partners' Interest	154	8
Add: Limited Partners' Interest in Discontinued Operations	(266)	49
Limited Partners' Interest in Net Income (Loss)	$ (112)	$ 57
Limited Partners' Net Income (Loss) per Unit:		
Income from Continuing Operations	$ 0.46	$ 0.03
Income (Loss) from Discontinued Operations	(0.79)	0.15
Net Income (Loss)	$ (0.33)	$ 0.18
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income (Loss) per Unit	338	317
Per Unit Cash Distribution Declared	$ 1.20	$ 1.14

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 March 31,	
	2012	**2011**
Net Income	$ 208	$ 341
Other Comprehensive Loss:		
Change in fair value of derivatives utilized for hedging purposes	(114)	(263)
Reclassification of change in fair value of derivatives to net income	31	53
Foreign currency translation adjustments	38	51
Adjustments to pension and other postretirement benefit plan liabilities, net of tax	(1)	(13)
Total Other Comprehensive Loss	(46)	(172)
Comprehensive Income	162	169
Comprehensive Income Attributable to Noncontrolling Interests	(1)	(1)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 161	$ 168

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)

	March 31, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 491	$ 409
Accounts, notes and interest receivable, net	747	884
Inventories	177	110
Gas in underground storage	58	62
Fair value of derivative contracts	67	72
Assets held for sale	2,287	-
Other current assets	23	39
Total Current assets	3,850	1,576
Property, plant and equipment, net	14,916	15,596
Investments	1,782	3,346
Notes receivable	167	165
Goodwill	1,356	1,436
Other intangibles, net	1,132	1,152
Fair value of derivative contracts	516	632
Deferred charges and other assets	182	200
Total Assets	$ 23,901	$ 24,103
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 891	$ 1,638
Cash book overdrafts	63	21
Accounts payable	602	706
Accrued interest	96	259
Accrued taxes	66	38
Deferred revenues	108	100
Fair value of derivative contracts	146	121
Accrued other current liabilities	334	236
Total Current liabilities	2,306	3,119
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	12,156	11,159
Value of interest rate swaps	955	1,079
Total Long-term debt	13,111	12,238
Deferred income taxes	258	250
Fair value of derivative contracts	83	39
Other long-term liabilities and deferred credits	832	853
Total Long-term liabilities and deferred credits	14,284	13,380
Total Liabilities	16,590	16,499
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units	4,131	4,347
Class B units	34	42
i-units	2,824	2,857
General partner	270	259
Accumulated other comprehensive (loss) income	(42)	3
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	7,217	7,508
Noncontrolling interests	94	96
Total Partners' Capital	7,311	7,604
Total Liabilities and Partners' Capital	$ 23,901	$ 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)

	Three Months Ended March 31,	
	2012	**2011**
Cash Flows From Operating Activities		
Net Income	$ 208	$ 341
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)	322	-
Depreciation, depletion and amortization	246	222
Amortization of excess cost of equity investments	2	1
Noncash compensation expense allocated from parent (Note 9)	-	90
Earnings from equity investments	(87)	(65)
Distributions from equity investments	80	65
Changes in components of working capital:		
Accounts receivable	83	100
Inventories	(73)	-
Other current assets	36	20
Accounts payable	(103)	(39)
Cash book overdrafts	42	3
Accrued interest	(162)	(148)
Accrued taxes	35	34
Accrued liabilities	71	(21)
Rate reparations, refunds and other litigation reserve adjustments	-	(63)
Other, net	(42)	(19)
Net Cash Provided by Operating Activities	658	521
Cash Flows From Investing Activities		
Acquisitions of assets and investments	(30)	(66)
Capital expenditures	(353)	(265)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	-	1
Net proceeds from margin and restricted deposits	16	43
Contributions to equity investments	(49)	(22)
Distributions from equity investments in excess of cumulative earnings	43	79
Net Cash Used in Investing Activities	(373)	(230)
Cash Flows From Financing Activities		
Issuance of debt	2,420	2,523
Payment of debt	(2,160)	(2,305)
Debt issue costs	(6)	(7)
Proceeds from issuance of common units	124	81
Contributions from noncontrolling interests	2	2
Distributions to partners and noncontrolling interests:		
Common units	(270)	(247)
Class B units	(6)	(6)
General Partner	(307)	(278)
Noncontrolling interests	(7)	(7)
Net Cash Used in Financing Activities	(210)	(244)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	7	2
Net increase in Cash and Cash Equivalents	82	49
Cash and Cash Equivalents, beginning of period	409	129
Cash and Cash Equivalents, end of period	$ 491	$ 178

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)

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
Noncash Investing and Financing Activities				
Liabilities settled by the issuance of common units	$	7	$	-
Contribution of net assets to investments	$	-	$	8
Supplemental Disclosures of Cash Flow Information				
Cash paid during the period for interest (net of capitalized interest)	$	272	$	251
Cash paid during the period for income taxes	$	4	$	1

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 8). Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals, and handle such products as ethanol, coal, petroleum coke and steel. We are also the leading producer and transporter of carbon dioxide, commonly called 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 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 March 31, 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 12.4% interest in us.

On October 16, 2011, KMI and El Paso Corporation (EP) announced a definitive agreement whereby KMI will acquire all of the outstanding shares of EP in a transaction that would create one of the largest energy companies in the U.S. On March 2, 2012, 100% of all KMI's voting shareholders approved the proposed EP acquisition, and on March 9, 2012, more than 95% of voting EP shareholders approved the acquisition. The transaction is subject to customary regulatory approvals, and currently, KMI expects this transaction to close at the end of May 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 portion of 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 occur contemporaneously with the closing of our divestiture. For more information about this announced 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. 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.

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

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

Following KMI's March 15, 2012 announcement of its intention to sell the assets that comprise our FTC Natural Gas Pipelines disposal group (described above in "—Kinder Morgan, Inc. and Kinder Morgan G.P., Inc."), we accounted for the disposal group as discontinued operations in accordance with the provisions of the "Presentation of Financial Statements—Discontinued Operations" Topic of the Codification. Accordingly, we (i) reclassified and excluded the FTC Natural Gas Pipelines disposal group's results of operations from our results of continuing operations and reported the disposal group's results of operations separately as "Income from operations of FTC Natural Gas Pipelines disposal group" within the discontinued operations section of our accompanying consolidated statements of income for all periods presented; (ii) separately reported a "Loss 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 three months ended March 31, 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 March 31, 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 March 31, 2012. In addition, we did not elect to present separately the operating and investing 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.

Limited Partners' Net (Loss) Income per Unit

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

2. FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

As described above in Note 1 "General—Basis of Presentation", we began accounting for our FTC Natural Gas Pipelines disposal group as discontinued operations in the first quarter of 2012. We recognized a $322 million loss on remeasurement to fair value. 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 three months ended March 31, 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 March 31, 2012 (because the disposal group's combined liabilities were not material to our consolidated balance sheet as of March 31, 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 March 31, 2012	Three Months Ended March 31, 2011
Operating revenues	$ 71	$ 76
Operating expenses	(37)	(38)
Depreciation and amortization	(7)	(7)
Earnings from equity investments	22	18
Interest income and Other, net	1	1
Earnings from discontinued operations	$ 50	$ 50

3. Goodwill and Other Intangibles

Goodwill and Excess Investment Cost

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes, but combined with Products Pipelines for presentation in the table below); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2011 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 8.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for the three months ended March 31, 2012 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Historical Goodwill.	$ 263	$ 557	$ 46	$ 326	$ 621	$ 1,813
Accumulated impairment losses(a)	-	-	-	-	(377)	(377)
Balance as of December 31, 2011	263	557	46	326	244	1,436
Acquisitions	-	-	-	-	-	-
Disposals(b)	-	(85)	-	-	-	(85)
Impairments	-	-	-	-	-	-
Currency translation adjustments	-	-	-	-	5	5
Balance as of March 31, 2012	$ 263	$ 472	$ 46	$ 326	$ 249	$ 1,356

(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of U.S. generally accepted accounting principles, the consideration of this transaction caused KMI to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, KMI recorded a goodwill impairment charge of $377 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment is now included in our accumulated impairment losses.

(b) Amount represents reclassification of FTC Natural Gas Pipelines disposal group's goodwill to "Assets held for sale." Since our FTC Natural Gas Pipelines disposal group represents a significant portion of our Natural Gas Pipelines business segment, we allocated the goodwill of the segment based on the relative fair value of the portion being disposed of and the portion of the segment remaining.

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing. For all investments we own containing equity method goodwill, no event or change in circumstances that may have a significant adverse effect on the fair value of our equity investments has occurred during the first three months of 2012. As of both March 31, 2012 and December 31, 2011, we included $138 million in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, lease value, and technology-based assets. These intangible assets have definite lives and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. Following is information related to our intangible assets subject to amortization (in millions):

	March 31, 2012	December 31, 2011
Customer contracts, relationships and agreements		
Gross carrying amount	$ 1,318	$ 1,318
Accumulated amortization	(193)	(173)
Net carrying amount	1,125	1,145
Lease value, technology-based assets and other		
Gross carrying amount	11	11
Accumulated amortization	(4)	(4)
Net carrying amount	7	7
Total Other intangibles, net	$ 1,132	$ 1,152

The net carrying amount of our intangible assets decreased $20 million during the first three months of 2012 due to amortization. We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. Among the factors we weigh, depending on the nature of the asset, are the effects of obsolescence, new technology, and competition. For the three months ended March 31, 2012 and 2011, the amortization expense on our intangibles totaled $20 million and $10 million, respectively. As of March 31, 2012, the weighted average amortization period for our intangible assets was approximately 18 years, and our estimated amortization expense for these assets for each of the next five fiscal years (2013 – 2017) is approximately $80 million, $80 million, $76 million, $60 million and $58 million, respectively.

4. Debt

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

The net carrying amount of our debt (including both short-term and long-term amounts and excluding the value of interest rate swap agreements) as of March 31, 2012 and December 31, 2011 was $13,047 million and $12,797 million, respectively. The weighted average interest rate on all of our borrowings was approximately 4.23% during the first quarter of 2012, and approximately 4.44% during the first quarter of 2011.

Our outstanding short-term debt as of March 31, 2012 was $891 million. The balance consisted of (i) $500 million in principal amount of 5.85% senior notes due September 15, 2012; (ii) $358 million of commercial paper borrowings; (iii) $24 million in principal amount of tax-exempt bonds that mature on April 1, 2024, that are due on demand pursuant to certain standby purchase agreement provisions contained in the bond indenture (our subsidiary Kinder Morgan Operating L.P. "B" is the obligor on the bonds); (iv) an $8 million portion of 5.23% long-term senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (v) a $1 million 7.17% note payable (our subsidiary Globalplex Partners, a Louisiana joint venture owned 50% and controlled by Kinder Morgan Bulk Terminals, Inc. is the obligor on the note, and we expect the joint venture will terminate during 2012).

Credit Facility

Our $2.2 billion senior unsecured revolving credit facility matures July 1, 2016 and can be amended to allow for borrowings of up to $2.5 billion. Borrowings under our credit facility can be used for general partnership purposes and as a backup for our commercial paper program. There were no borrowings under the credit facility as of March 31, 2012 or as of December 31, 2011.

Additionally, as of March 31, 2012, the amount available for borrowing under our credit facility was reduced by a combined amount of $584 million, consisting of $358 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.

Commercial Paper Program

Our commercial paper program provides for the issuance of up to $2.2 billion of commercial paper. Our $2.2 billion senior unsecured revolving credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of March 31, 2012, we had $358 million of commercial paper outstanding with an average interest rate of 0.45%. As of December 31, 2011, we had $645 million of commercial paper outstanding with an average interest rate of 0.53%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2012 and 2011, and in the near term, we expect that our short-term liquidity and financing needs will be met primarily through borrowings made under our commercial paper program.

Kinder Morgan Energy Partners, L.P. Senior Notes

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 to both repay our $450 million 7.125% senior notes that matured on March 15, 2012 and reduce the borrowings under our commercial paper program.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 6 "Risk Management—Interest Rate Risk Management."

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. As of March 31, 2012, our contingent debt obligations, as well as our obligations with respect to related letters of credit, consisted of the following two items (dollars in millions):

Entity	Our Ownership Interest	Investment Type	Total Entity Debt	Our Contingent Share of Entity Debt (a)
Cortez Pipeline Company(b)	50%	General Partner	$ 136(c)	$ 79(d)
Nassau County, Florida Ocean Highway and Port Authority(e)	N/A	N/A	N/A	$ 17(f)

(a) Represents the portion of the entity's debt that we may be responsible for if the entity cannot satisfy its obligations.

(b) Cortez Pipeline Company is a Texas general partnership that owns and operates a common carrier carbon dioxide pipeline system. The remaining general partner interests are owned by ExxonMobil Cortez Pipeline, Inc., an indirect wholly-owned subsidiary of Exxon Mobil Corporation, and Cortez Vickers Pipeline Company, an indirect subsidiary of M.E. Zuckerman Energy Investors Incorporated.

(c) Amount consists of (i) $22 million aggregate principal amount of Series D notes due May 15, 2013 (interest on the Series D notes is paid annually and based on a fixed interest rate of 7.14% per annum); (ii) $100 million of variable rate Series E notes due December 11, 2012 (interest on the Series E notes is paid quarterly and based on an interest rate of three-month LIBOR plus a spread); and (iii) $14 million of outstanding borrowings under a $40 million committed revolving bank credit facility that is also due December 11, 2012.

(d) We are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt ($68 million). In addition, as of March 31, 2012, Shell Oil Company shares our several guaranty obligations jointly and severally for $22 million of Cortez's debt balance related to the Series D notes; however, we are obligated to indemnify Shell for the liabilities it incurs in connection with such guaranty. Accordingly, as of March 31, 2012, we have a letter of credit in the amount of $11 million issued by JP Morgan Chase, in order to secure our indemnification obligations to Shell for 50% of the Cortez debt balance of $22 million related to the Series D notes.

Further, pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company are required to contribute capital to Cortez in the event of a cash deficiency. The agreement contractually supports the financings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline to fund cash deficiencies at Cortez Pipeline, including anticipated deficiencies and cash deficiencies relating to the repayment of principal and interest on the debt of Cortez Capital Corporation. The partners' respective parent or other companies further severally guarantee the obligations of the Cortez Pipeline owners under this agreement.

(e) Arose from our Vopak terminal acquisition in July 2001. Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the state of Florida.

(f) We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year, and corresponding reductions are made to the letter of credit. As of March 31, 2012, this letter of credit had a face amount of $17 million.

For additional information regarding our debt facilities and 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.

5. Partners' Capital

Limited Partner Units

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

	March 31, 2012	December 31, 2011
Common units	234,225,456	232,677,222
Class B units	5,313,400	5,313,400
i-units	99,973,534	98,509,389
Total limited partner units	339,512,390	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 March 31, 2012, our total common units consisted of 217,855,028 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2011, our total common units consisted of 216,306,794 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner.

As of both March 31, 2012 and December 31, 2011, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange.

As of both March 31, 2012 and December 31, 2011, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. 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 three month periods ended March 31, 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):

	Three Months Ended March 31, 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	124	-	124	81	-	81
Units issued as consideration in the acquisition of assets	7	-	7	-	-	-
Distributions paid in cash	(583)	(7)	(590)	(531)	(7)	(538)
Noncash compensation expense allocated from KMI(a)	-	-	-	89	1	90
Cash contributions	-	2	2	-	2	2
Other adjustments	-	2	2	1	-	1
Comprehensive income	161	1	162	168	1	169
Ending Balance	$ 7,217	$ 94	$ 7,311	$ 7,019	$ 79	$ 7,098

(a) For further information about this expense, see Note 9. We do not have any obligation, nor do we expect to pay any amounts related to this expense.

During the first three months of both 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) to provide for the offer and sale of common units having an aggregate offering price of up to $1.9 billion (up from an aggregate offering price of up to $1.2 billion under our second amended and restated agreement) from time to time through UBS, as our sales agent. Sales of the units will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we also may sell common units to UBS as principal for its own account at a price agreed upon at the time of the sale. Any sale of common units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS.

During the three months ended March 31, 2012, we issued 1,461,072 of our common units pursuant to our equity distribution agreement with UBS. We received net proceeds of $124 million from the issuance of these common units. 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.

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 February 14, 2012, we paid a cash distribution of $1.16 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended December 31, 2011. KMR, our sole i-unitholder, received a distribution of 1,464,145 i-units from us on February 14, 2012, based on the $1.16 per unit distributed to our common unitholders on that date. The distributions were declared on January 18, 2012, payable to unitholders of record as of January 31, 2012.

On February 14, 2011, we paid a cash distribution of $1.13 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended December 31, 2010. KMR, our sole i-unitholder, received a distribution of 1,598,556 i-units from us on February 14, 2011, based on the $1.13 per unit distributed to our common unitholders on that date. The distributions were declared on January 19, 2011, payable to unitholders of record as of January 31, 2011.

Our general partner's incentive distribution that we paid in February 2012 and February 2011 (for the quarterly periods ended December 31, 2011 and December 31, 2010, respectively) was $302 million and $275 million, respectively. The increased incentive distribution to our general partner paid for the fourth quarter of 2011 over the incentive distribution paid for the fourth quarter of 2010 reflects the increase in the amount distributed per unit as well as the issuance of additional units. These incentive distributions were reduced from what they would have been, however, by waived incentive amounts equal to $8 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.

Subsequent Events

In early April 2012, we issued 157,559 of our common units for the settlement of sales made on or before March 31, 2012 pursuant to our equity distribution agreement. We received net proceeds of $13 million from the issuance of these 157,559 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On April 18, 2012, we declared a cash distribution of $1.20 per unit for the quarterly period ended March 31, 2012. The distribution will be paid on May 15, 2012, to unitholders of record as of April 30, 2012. Our common unitholders and our Class B unitholder will receive cash. KMR will receive a distribution of 1,603,975 additional i-units based on the $1.20 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.016044) will be issued. This fraction was determined by dividing:

- $1.20, the cash amount distributed per common unit

by

- $74.794, the average of KMR's shares' closing market prices from April 12-25, 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.

Our declared distribution for the first quarter of 2012 of $1.20 per unit will result in an incentive distribution to our general partner of $319 million (including the effect of a waived incentive distribution amount of $6 million related to our KinderHawk acquisition). Comparatively, our distribution of $1.14 per unit paid on May 13, 2011 for the first quarter of 2011 resulted in an incentive distribution payment to our general partner in the amount of $280 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 first quarter of 2012 over the incentive distribution for the first quarter of 2011 reflects the increase in the distribution per unit as well as the issuance of additional units. 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.

On April 25, 2012, we announced that we had signed a definitive agreement with an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. (together with its affiliates, referred to as KKR) to purchase from KKR its 50% ownership interest in the 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 gathering system located in the Eagle Ford shale formation in South Texas. We will acquire our equity interest for an aggregate consideration of $300 million in common units. We expect this transaction will close subsequent to the completion of KMI's acquisition of EP, which is expected to close at the end of May 2012, and we will include our investment in our Natural Gas Pipelines business segment. EP owns the remaining 50% interest in the joint venture.

6. Risk Management

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

Energy Commodity Price Risk Management

As of March 31, 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	(22.3) million barrels
Natural gas fixed price	(32.9) billion cubic feet
Natural gas basis	(36.1) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas fixed price	(1.8) billion cubic feet
Natural gas basis	20.1 billion cubic feet

As of March 31, 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 March 31, 2012, we had a combined notional principal amount of $5,625 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 March 31, 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.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported (i) separately as "Fair value of derivative contracts;" or (ii) included within "Assets held for sale" and "Accrued other current liabilities" in the respective sections of our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of March 31, 2012 and December 31, 2011 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
	Balance sheet location	March 31, 2012 Fair value	December 31, 2011 Fair value	March 31, 2012 Fair value	December 31, 2011 Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	$ 63	$ 66	$ (143)	$ (116)
	Current-Assets held for Sale / Accrued other current liabilities	6	-	(1)	-
	Non-current-Fair value of derivative contracts	17	39	(66)	(39)
Subtotal		86	105	(210)	(155)
Interest rate swap agreements	Current-Fair value of derivative contracts	1	3	-	-
	Non-current-Fair value of derivative contracts	499	593	(17)	-
Subtotal		500	596	(17)	-
Total		586	701	(227)	(155)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	3	3	(3)	(5)
Total		3	3	(3)	(5)
Total derivatives		$ 589	$ 704	$ (230)	$ (160)

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Value of interest rate swaps" on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of March 31, 2012 and December 31, 2011, this unamortized premium totaled $472 million and $483 million, respectively, and as of March 31, 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 months ended March 31, 2012 and 2011 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a) Three Months Ended March 31, 2012	2011
Interest rate swap agreements	Interest expense	$ (113)	$ (64)
Total		$ (113)	$ (64)

Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged items(a) Three Months Ended March 31, 2012	2011
Fixed rate debt	Interest expense	$ 113	$ 64
Total		$ 113	$ 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) recognized 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 March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2012	2011		2012	2011		2012	2011
Energy commodity derivative contracts	$ (114)	$ (263)	Revenues–Natural gas sales	$ -	$ 1	Revenues–Natural gas sales	$ -	$ -
			Revenues–Product sales and other	(29)	(65)	Revenues–Product sales and other	(3)	4
			Gas purchases and other costs of sales	(2)	11	Gas purchases and other costs of sales	-	-
Total	$ (114)	$ (263)	Total	$ (31)	$ (53)	Total	$ (3)	$ 4

(a) We expect to reclassify an approximate $79 million loss associated with energy commodity price risk management activities and included in our Partners' Capital as of March 31, 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 months ended March 31, 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 March 31, 2012 was (in millions):

	Asset position
Interest rate swap agreements	$ 500
Energy commodity derivative contracts	89
Gross exposure	589
Netting agreement impact	(44)
Cash collateral held	(26)
Net exposure	$ 519

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 March 31, 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 March 31, 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 $26 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 March 31, 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 $53 million of additional collateral.

7. Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

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

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

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of March 31, 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 us or our counterparties, which would be reported within "Restricted deposits" and "Accrued other current liabilities," respectively, in our accompanying consolidated balance sheets.

		Asset fair value measurements using		
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of March 31, 2012				
Energy commodity derivative contracts(a)	$ 89	$ 48	$ 25	$ 16
Interest rate swap agreements	$ 500	$ -	$ 500	$ -
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 liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of March 31, 2012				
Energy commodity derivative contracts(a)	$ (213)	$ (12)	$ (182)	$ (19)
Interest rate swap agreements	$ (17)	$ -	$ (17)	$ -
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 months ended March 31, 2012 and 2011 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended March 31,	
	2012	2011
Derivatives-net asset (liability)		
Beginning of period	$ 7	$ 19
Transfers into Level 3	-	-
Transfers out of Level 3	-	-
Total gains or (losses):		
Included in earnings	2	-
Included in other comprehensive income	(22)	(23)
Purchases	3	5
Issuances	-	-
Sales	-	-
Settlements	7	(4)
End of period	$ (3)	$ (3)
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets held at the reporting date	$ 2	$ -

As of March 31, 2012, our West Texas Intermediate options were reported at fair value using Level 3 inputs due to such derivatives not having observable market prices. Fair value of West Texas Intermediate options is determined 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 used in the fair value measurement of our Level 3 derivatives is implied volatility of options. Implied volatility of our West Texas Intermediate options is obtained from a third party service provider. As of March 31, 2012, this volatility ranged from 25% – 27% 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 March 31, 2012 and December 31, 2011 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	March 31, 2012		December 31, 2011	
	Carrying Value	Estimated Fair value	Carrying Value	Estimated Fair value
Total debt	$ 13,047	$ 14,486	$ 12,797	$ 14,238

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

8. 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 March 31,	
	2012	2011
Revenues		
Products Pipelines		
Revenues from external customers	$ 223	$ 225
Natural Gas Pipelines		
Revenues from external customers	794	943
CO_2		
Revenues from external customers	417	341
Terminals		
Revenues from external customers	341	332
Kinder Morgan Canada		
Revenues from external customers	73	76
Total segment revenues	1,848	1,917
Less: Total intersegment revenues	-	-
Total consolidated revenues	$ 1,848	$ 1,917

	Three Months Ended March 31, 2012	2011
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)		
Products Pipelines	$ 176	$ 180
Natural Gas Pipelines	222	166
CO_2	334	262
Terminals	187	174
Kinder Morgan Canada	50	48
Total segment earnings before DD&A	969	830
Total segment depreciation, depletion and amortization	(239)	(215)
Total segment amortization of excess cost of investments	(2)	(1)
General and administrative expenses(b)	(107)	(189)
Interest expense, net of unallocable interest income	(139)	(132)
Unallocable income tax expense	(2)	(2)
(Loss) Income from discontinued operations(c)	(272)	50
Total consolidated net income	$ 208	$ 341

	March 31, 2012	December 31, 2011
Assets		
Products Pipelines	$ 4,590	$ 4,479
Natural Gas Pipelines	7,267	9,958
CO_2	2,187	2,147
Terminals	4,534	4,428
Kinder Morgan Canada	1,838	1,827
Total segment assets	20,416	22,839
Corporate assets(d)	1,198	1,264
Assets held for sale(e)	2,287	-
Total consolidated assets	$ 23,901	$ 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) First quarter 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.

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

(d) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to the fair value of interest rate swaps.

(e) Represents our FTC Natural Gas Pipelines disposal group's "Assets held for sale."

9. Related Party Transactions

Notes Receivable

Plantation Pipe Line Company

We and ExxonMobil have a term loan agreement covering a note receivable due from Plantation Pipe Line Company. We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was $50 million as of both March 31, 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 March 31, 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 March 31, 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 $114 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 March 31, 2012 and December 31, 2011, our related party receivables (other than notes receivable discussed above in "—Notes Receivable") totaled $12 million and $26 million, respectively. The March 31, 2012 receivables amount consisted of (i) $10 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 $10 million receivable amount consisted primarily of amounts due from the Express pipeline system, the Plantation Pipe Line Company, and KMI. The $2 million natural gas imbalance receivable consisted primarily of amounts due from the Rockies Express pipeline system.

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, Natural Gas Pipeline Company of America LLC, a 20%-owned equity investee of KMI and referred to in this report as NGPL, and KMI. The $11 million natural gas imbalance receivable consisted of amounts due from both NGPL and the Rockies Express pipeline system.

As of March 31, 2012 and December 31, 2011, our related party payables totaled $2 million and $1 million, respectively, and we included these amounts within "Accounts payable" on our accompanying consolidated balance sheets. At each balance sheet date, our related party payables included a $1 million amount we owed to the noncontrolling partner of Globalplex Partners, a Louisiana joint venture owned 50% and controlled by us. The March 31, 2012 payable amount also included amounts due to the Cortez Pipeline Company.

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 three 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 March 31, 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 March 31, 2012 and December 31, 2011 (in millions):

	March 31, 2012	December 31, 2011
Derivatives – asset/(liability)		
Current assets	$ 1	$ 9
Noncurrent assets	$ 7	$ 18
Current liabilities	$ (67)	$ (64)
Noncurrent liabilities	$ (15)	$ (10)

For more information on our risk management activities see Note 6.

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

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.

10. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the three months ended March 31, 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. This note also contains a description of any material legal proceedings that were initiated against us during the three months ended March 31, 2012, and a description of any material events occurring subsequent to March 31, 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 as ConocoPhillips; Tesoro Refining and Marketing Company as Tesoro; Western Refining Company, L.P. as Western Refining; Navajo Refining Company, L.L.C. as Navajo; Holly Refining & Marketing Company LLC as Holly; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Kinder Morgan 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; the Texas Commission of Environmental Quality as the TCEQ; The Premcor Refining Group, Inc. as Premcor; Port Arthur Coker Company as PACC; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; the federal Comprehensive Environmental Response, Compensation and Liability Act as CERCLA; the United States Environmental Protection Agency as the U.S. EPA; the United States Environmental Protection Agency's Suspension and Debarment Division as the U.S. EPA SDD; the New Jersey Department of Environmental Protection as the NJDEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Liquids Terminals LLC as KMLT; our subsidiary Kinder Morgan Interstate Gas Transmission LLC as KMIGT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. "OR" dockets designate complaint proceedings, and "IS" dockets designate protest proceedings.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP and Calnev are subject to a number of ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. In general, these complaints and protests allege the rates and tariffs charged by SFPP and Calnev are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaints) or refunds of any excess rates paid, and SFPP and/or Calnev may be required to reduce their rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

The issues involved in these proceedings include, among others: (i) whether certain of our rates are "grandfathered" under the Energy Policy Act of 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases are justified; and (iv) the appropriate level of return and income tax allowance we may include in our rates.

SFPP

The following FERC dockets are currently pending:

- FERC Docket No. IS08-390 (West Line Rates) (Opinion Nos. 511 and 511-A)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Status: FERC order issued on December 16, 2011 (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 filed petitions at the D.C. Circuit for review of Opinion Nos. 511 and 511-A. 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, Holly, and Southwest Airlines—Status: Initial decision issued on February 10, 2011. A FERC administrative law judge generally made findings adverse to SFPP, found that East Line rates should have been lower, and recommended that SFPP pay refunds for alleged over-collections. SFPP has filed a brief with the FERC taking exception to these and other portions of the initial decision. The FERC will review the initial decision, and while the initial decision is inconsistent with a number of the issues ruled on in FERC's Opinion Nos. 511 and 511-A, it is not possible to predict the outcome of FERC or appellate review;

- FERC Docket No. IS11-444 (2011 Index Rate Increases)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines, Tesoro, Western Refining, Navajo, and Holly—Status: SFPP withdrew all index rate increases except those that pertain to the West Line. As to the West Line, the shippers filed a motion for summary disposition that was granted in an initial decision issued on March 16, 2012. SFPP is filing 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. OR11-13 (SFPP Base Rates)—Complainant: ConocoPhillips—Status: SFPP to provide further data within 90 days of the issuance of a final order in Docket No. IS08-390. ConocoPhillips permitted to amend its complaint based on additional data;

- FERC Docket No. OR11-16 (SFPP 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;

- 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; and

- FERC Docket Nos. OR12-1, 12-2 and 12-3 (SFPP Index Ceiling Levels)—Complainants: Chevron, Tesoro and ConocoPhillips—Status: FERC dismissed the complaints on February 16, 2012.

With respect to the SFPP proceedings above, we estimate that the shippers are seeking approximately $20.0 million in annual rate reductions and approximately $100.0 million in refunds. However, applying the principles of Opinion Nos. 511 and 511-A, a full FERC decision on our West Line rates, to these cases would result in substantially lower rate reductions and refunds. We do not expect refunds in these cases to have an impact on our distributions to our limited partners.

Calnev

On March 17, 2011, the FERC issued an order consolidating 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, ConocoPhillips 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. Certain shippers will receive settlement payments of approximately $54 million in May 2012 after the rates reduced by the settlement go into effect.

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 Appeal, seeking a court order vacating the CPUC's determination that SFPP is not entitled to recover an income tax allowance in its intrastate rates.

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, ordering SFPP to pay refunds from May 24, 2007 to the present of revenues collected in excess of the authorized cost of service. Comments on the proposed decision are due April 26, 2012, and SFPP will assert what it believes to be errors in law and in fact in the proposed decision, including the requirement that refunds be made from May 24, 2007. SFPP is also entitled to an oral argument before the CPUC regarding the proposed decision.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately $375.0 million in reparation payments and approximately $30.0 million in annual rate reductions. The actual amount of reparations will be determined through further proceedings at the CPUC and 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 will be held on our appeal within the next several months.

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 $18 million amount for interest on the outstanding back rent liability. We believe the award of interest is without merit.

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 is 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 Sparrows Point, LLC and located in Sparrows Point, Maryland collapsed while being operated by KMBT. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the United States District Court for the District of Maryland, Case No. 09CV1668-WMN. Severstal and its successor in interest, RG Steel Sparrows Point LLC ("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 Severstal's allegations. Trial is presently scheduled to begin on October 22, 2012.

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 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 March 31, 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 $333 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 filed motions to dismiss, which were denied, and now have filed interlocutory appeals from those motions. The appeals court panel heard oral arguments on these motions to dismiss in March 2012. We are waiting on the appeal panel’s decisions. KMLT is part of the third party defendant Joint Defense Group. We have filed an Answer and initial disclosures. 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. We are cooperating with the U.S. EPA and working with the U.S. EPA to resolve these allegations.

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

KMLT is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed beginning in 2009 and remains stayed through the next case management conference in May 2012. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup and are now starting a sampling and testing program at the site. We anticipate that cleanup activities at the site will begin in the Fall of 2012. 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, however we are now approaching settlement discussions with ExxonMobil. There is no trial date set.

Mission Valley Terminal Lawsuit

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

The Court issued a Case Management Order on January 6, 2011, setting dates for completion of discovery and setting a trial date. In April 2011, the parties filed a joint stipulation to extend the discovery schedule by approximately 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. Currently, the parties are conducting expert discovery. All dispositive motions must be filed by June 29, 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.

Notice of Proposed Debarment

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

Our objective is to fully comply with all applicable legal requirements and to operate our assets in accordance with our processes, procedures and compliance plans. We are performing better than industry averages in our incident rates and in our safety performance, all of which is publicly reported on our internet website. We take environmental compliance very seriously, and look forward to demonstrating our present responsibility to the U.S. EPA SDD through this administrative process and we are engaged in discussions with the U.S. EPA SDD with the goal of resolving this matter in a cooperative fashion. We have reached a tentative agreement on the term of a proposed Administrative Agreement which, if approved by the U.S. EPA, would resolve this matter without the debarment of any Kinder Morgan entities. The proposed Administrative Agreement is currently under review by the U.S. EPA's Suspension and Debarment Official. The proposed Administrative Agreement would require 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 do not anticipate that the resolution of this matter will have a material adverse impact on our business, financial position, results of operations or cash flows.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or cash flows.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of March 31, 2012, we have accrued an environmental reserve of $74 million (including $1 million of environmental related liabilities belonging to our FTC Natural Gas Pipelines disposal group). In addition, as of March 31, 2012, we have recorded a receivable of $5 million for expected cost recoveries that have been deemed probable. As of December 31, 2011, our environmental reserve totaled $75 million and our estimated receivable for environmental cost recoveries totaled $5 million. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

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

11. Regulatory Matters

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. The amount of regulatory assets and liabilities reflected within "Deferred charges and other assets" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets as of March 31, 2012 and December 31, 2011 are not material to our consolidated balance sheets.

For information on our pipeline regulatory proceedings, see Note 10 "Litigation, Environmental and Other Contingencies—Federal Energy Regulatory Commission Proceedings" and "California Public Utilities Commission Proceedings."

12. Recent Accounting Pronouncements

Accounting Standards Updates

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

ASU No. 2011-11

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

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

The profitability of our refined petroleum products pipeline transportation business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. Transportation volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, in our Texas Intrastate Pipeline business, we currently derive approximately 75% of our sales and transport margins from long-term transport and sales contracts that include requirements with minimum volume payment obligations. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2011, the remaining average contract life of our natural gas transportation contracts (including our intrastate pipelines) was approximately eight years.

Our CO_2 sales and transportation business primarily has contracts with minimum volume requirements, which as of March 31, 2012, had a remaining average contract life of approximately eight years (this remaining average contract life includes intercompany sales; when we eliminate intercompany sales, the remaining average contract life is approximately nine years). Carbon dioxide sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for contracts making deliveries in 2012, and utilizing the average oil price per barrel contained in our 2012 budget, approximately 70% of our contractual volumes are based on a fixed fee or floor price, and 30% fluctuate with the price of oil (these percentages include intercompany sales; when we eliminate intercompany sales, the percentages are 72% and 28%, respectively). In the long-term, our success in this business is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In our CO_2 segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, natural gas liquids and carbon dioxide sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. Our realized weighted average crude oil price per barrel, with all hedges allocated to oil, was $90.63 per barrel in the first quarter of 2012, and $68.78 per barrel in the first quarter of 2011. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $100.62 per barrel in the first quarter of 2012, and $90.76 per barrel in the first quarter of 2011.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. As with our refined petroleum products pipeline transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are coal, petroleum coke, and steel. For the most part, we have contracts for this business that have minimum volume guarantees and are volume based above the minimums. Because these contracts are volume based above the minimums, our profitability from the bulk business can be sensitive to economic conditions. Our liquids terminals business generally has longer-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which is typically approximately four years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

In our discussions of the operating results of individual businesses that follow (see "—Results of Operations" below), we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods. Continuing our history of making accretive acquisitions and economically advantageous expansions of existing businesses, in 2011, we invested approximately $2.6 billion for both strategic business acquisitions and expansions of existing assets. Our capital investments have helped us to achieve compound annual growth rates in cash distributions to our limited partners of 4.8%, 4.7% and 7.2%, respectively, for the one-year, three-year and five-year periods ended December 31, 2011.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets and we have forecasted approximately $1.9 billion for our 2012 capital expansion program, including small acquisitions and investment contributions. Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

On April 12, 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 850,000 barrels per day. The project 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 $5 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. Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

Currently, we expect KMI to offer to sell (drop-down) all of the Tennessee Gas Pipeline system and a portion of 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), and we expect that these drop-downs will occur contemporaneously with the closing of our divestiture. We also expect that the combination of the asset divestitures and drop-downs will be neutral to our distribution per unit in 2012 and accretive thereafter. For more information about the divestiture of our FTC Natural Gas Pipelines disposal group, see Notes 1 and 2 to our consolidated financial statements included elsewhere in this report.

Our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, including our public debt and equity offerings in the first three months of 2012, please see "—Financial Condition" below.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of U.S. generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Furthermore, with regard to goodwill impairment testing, we review our goodwill for impairment annually, and we evaluated our goodwill for impairment on May 31, 2011. Our goodwill impairment analysis performed on that date did not result in an impairment charge, 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. For more information on our goodwill impairment analysis, see Note 3 "Goodwill and Other Intangibles—Goodwill and Excess Investment Cost" to our consolidated financial statements included elsewhere in this report.

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.

Results of Operations

Consolidated

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines	$ 176	$ 180	$ (4)	(2)%
Natural Gas Pipelines	222	166	56	3 %
CO_2(b)	334	262	72	27 %
Terminals(c)	187	174	13	7 %
Kinder Morgan Canada	50	48	2	4 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	969	830	139	17 %
Depreciation, depletion and amortization expense	(239)	(215)	(24)	(11)%
Amortization of excess cost of equity investments	(2)	(1)	(1)	(100)%
General and administrative expense(d)	(107)	(189)	82	43 %
Interest expense, net of unallocable interest income	(139)	(132)	(7)	(5)%
Unallocable income tax expense	(2)	(2)	-	-
Income from continuing operations	480	291	189	65 %
(Loss) Income from discontinued operations(e)	(272)	50	(322)	(644)%
Net income	208	341	(133)	(39)%
Net income attributable to noncontrolling interests(f)	(2)	(3)	1	33 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 206	$ 338	$ (132)	(39)%

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) 2012 and 2011 amounts include a $3 million decrease in income and a $4 million increase in income, respectively, from unrealized gains and losses on derivative contracts used to hedge forecast crude oil sales.

(c) 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 or realize any direct benefits related to this compensation expense); (ii) 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; (iii) a $2 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses; and (iv) a $1 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal.

(d) 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 (however, we do not have any obligation, nor did we pay any amounts related to this compensation expense); and (ii) a $1 million increase in expense for certain asset and business acquisition costs.

(e) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2012 amount consists of a $265 million loss before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (including a $322 million non-cash loss from a remeasurement of net assets to fair value), and $7 million of depreciation and amortization expense. 2011 amount consists of $57 million of earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments, and $7 million of depreciation and amortization expense.

(f) 2011 amount includes a $1 million decrease in net income attributable to our noncontrolling interests, related to the combined effect from all of the three month 2011 items previously disclosed in these footnotes.

Net income attributable to our partners—including all of our limited partner unitholders and our general partner—totaled $206 million for the three months ended March 31, 2012, a decrease of 39% from the $338 million reported for the same period last year. Total revenues for the comparable first quarter periods were $1,848 million in 2012 and $1,917 million in 2011.

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 first quarter periods, total segment earnings before depreciation, depletion and amortization expenses increased $139 million (17%) in 2012. However, this overall increase in earnings (i) included a decrease of $11 million from the effect of the certain items described in the footnotes (b) and (c) to the table above (which combined to decrease total segment EBDA by $3 million in the first quarter of 2012 and to increase total segment EBDA by $8 million in the first quarter of 2011); and (ii) excluded $57 million of segment earnings before depreciation, depletion and amortization from discontinued operations in each of the comparable first quarter periods (as described in footnote (e) to the table above and after taking into effect the $322 million non-cash loss from the remeasurement of net assets to fair value in the first quarter of 2012).

After adjusting for these two items, the remaining $150 million (17%) increase in quarterly segment earnings before depreciation, depletion and amortization resulted primarily from better performance in the first quarter of 2012 from our CO_2, Natural Gas Pipelines and Terminals business segments. Quarter-to-quarter earnings before depreciation, depletion and amortization from both our Kinder Morgan Canada and Products Pipelines business segment were essentially unchanged across both comparable periods.

Products Pipelines

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	increase/(decrease)	
	(In millions, except operating statistics and percentages)			
Revenues	$ 223	$ 225	$ (2)	(1)%
Operating expenses	(57)	(52)	(5)	(10)%
Earnings from equity investments	14	11	3	27%
Interest income and Other, net	2	1	1	100%
Income tax expense	(6)	(5)	(1)	(20)%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 176	$ 180	$ (4)	(2)%
Gasoline (MMBbl)(a)	95.1	95.9	(0.8)	(1)%
Diesel fuel (MMBbl)	33.6	36.6	(3.0)	(8)%
Jet fuel (MMBbl)	26.9	25.6	1.3	5%
Total refined product volumes (MMBbl)	155.6	158.1	(2.5)	(2)%
Natural gas liquids (MMBbl)	7.4	6.6	0.8	12%
Total delivery volumes (MMBbl)(b)	163.0	164.7	(1.7)	(1)%
Ethanol (MMBbl)(c)	7.3	7.3	-	-

(a) Volumes include ethanol pipeline volumes.

(b) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.

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

Earnings before depreciation, depletion and amortization expenses from our Products Pipelines business segment were relatively flat across both comparable first quarter periods. Following is information related to the increases and decreases, in the comparable three month periods of 2012 and 2011, in the segment's (i) $4 million (2%) decrease in earnings before depreciation, depletion and amortization; and (ii) $2 million (1%) decrease in operating revenues:

Three months ended March 31, 2012 versus Three months ended March 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ (8)	(10)%	$ (3)	(3)%
Calnev Pipeline	(3)	(19)%	(1)	(6)%
Plantation Pipeline	2	12 %	-	-
West Coast Terminals	2	8 %	3	11 %
Crude Oil & Condensate Pipeline	2	n/a	-	n/a
All others (including eliminations)	1	2 %	(1)	(2)%
Total Products Pipelines	$ (4)	(2)%	$ (2)	(1)%

The overall decrease in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the first quarter of 2012 compared to the first quarter of 2011 was chiefly due to a combined $11 million (11%) decrease in earnings from our Pacific and Calnev pipeline operations.

The decrease from our Pacific operations consisted of a $3 million decrease in revenues and a $5 million increase in combined operating expenses. Mainline transportation revenues declined in the first quarter of 2012 due mainly to lower average FERC tariffs as a result of rate case rulings settlements made since the end of the first quarter of 2011, and to lower military volumes. The increase in operating expenses was due mainly to lower product inventory gains and to higher expenses related to certain rights-of-way obligations and legal matters.

The decrease in earnings from our Calnev Pipeline was driven by both lower revenues and higher operating expenses in the first quarter of 2012. The decrease in revenues was driven by a 22% drop in ethanol handling volumes, related in part to incremental ethanol blending services offered by a competing terminal. The increase in Calnev's operating expenses resulted from both incremental product losses and higher environmental expenses.

Compared to the first quarter of 2011, the segment benefitted from (i) higher equity earnings from our approximate 51% interest in the Plantation pipeline system—due primarily to higher tariffs and higher oil loss allowance revenues; (ii) higher earnings from our West Coast terminal operations—due mainly to higher contract revenues and to the continuing completion of various terminal expansion projects that have increased liquids tank capacity at our combined Carson/Los Angeles Harbor terminal since the end of the first quarter of 2011; and (iii) lower expenses (due to higher construction expense capitalization) from the ongoing construction of our Crude and Condensate Pipeline.

Natural Gas Pipelines

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	increase/(decrease)	
	(In millions, except operating statistics and percentages)			
Revenues	$ 794	$ 943	$ (149)	(16)%
Operating expenses	(608)	(805)	197	25%
Earnings from equity investments	38	29	9	31%
Income tax expense	(2)	(1)	(1)	(100)%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments from continuing operations	222	$ 166	$ 56	34%
Discontinued operations(a)	(265)	57	(322)	(565)%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments including discontinued operations	$ (43)	$ 223	$ (266)	(119)%
Natural gas transport volumes (Bcf)(b)	736.3	707.7	28.6	4%
Natural gas sales volumes (Bcf)(c)	212.8	191.2	21.6	11%

(a) Represents earnings before depreciation, depletion and amortization expense attributable to our FTC Natural Gas Pipelines disposal group. 2012 and 2011 amounts include revenues of $71 million and $76 million, respectively. 2012 amount also includes a $322 million non-cash loss from the remeasurement of the FTC Natural Gas Pipelines disposal group to fair value.

(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.

The certain item described in footnote (a) to the table above decreased our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses from discontinued operations by $322 million in the first quarter of 2012, when compared to the first quarter of 2011. Following is information related to the increases and decreases, in the comparable three month periods of 2012 and 2011 and including discontinued operations, in the segment's (i) remaining $56 million (25%) increase in earnings before depreciation, depletion and amortization; and (ii) $154 million (15%) decrease in operating revenues:

Three months ended March 31, 2012 versus Three months ended March 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 35	360 %	$ 51	n/a
Fayetteville Express Pipeline(b)	12	n/m	n/a	n/a
Kinder Morgan Treating operations	7	68 %	17	105 %
EagleHawk Field Services(b)	3	n/a	n/a	n/a
Texas Intrastate Natural Gas Pipeline Group	(5)	(5)%	(217)	(24)%
All others (including eliminations)	4	8 %	-	-
Total Natural Gas Pipelines-continuing operations	$ 56	34 %	$ (149)	(16)%
Discontinued operations(c)	-	-	(5)	(6)%
Total Natural Gas Pipelines-including discontinued operations	$ 56	25 %	$ (154)	(15)%

n/m – not meaningful
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 increase included in our Natural Gas Pipelines business segment's overall quarter-to-quarter increase in earnings before depreciation, depletion and amortization expenses in the first quarter of 2012 compared to the first quarter of 2011 was 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.

The increase in segment earnings before depreciation, depletion and amortization was also favorably impacted by the following: (i) incremental equity earnings from our 50% interest in the Fayetteville Express pipeline system—due primarily to higher firm contract transportation revenues in the first three months of 2012; (ii) higher earnings 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; and (iii) incremental equity earnings from our 25%-owned EagleHawk Field Services LLC, which we acquired effective July 1, 2011.

Unfavorably impacting the overall increase in segment earnings before depreciation, depletion and amortization across the comparable first quarter periods was a lower contribution from our Texas intrastate natural gas pipeline group, primarily due to an $8 million decrease in natural gas sales margins.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three 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 quarter-to-quarter 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. In the comparable first quarter periods of 2012 and 2011, our Texas intrastate natural gas pipeline group accounted for 86% and 95%, respectively, of the segment's revenues, and 96% and 99%, respectively, of the segment's operating expenses.

CO_2

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	increase/(decrease)	
	(In millions, except operating statistics and percentages)			
Revenues(a)	$ 417	$ 341	$ 76	22%
Operating expenses	(87)	(84)	(3)	(4)%
Earnings from equity investments	6	6	-	-
Income tax (expense) benefit	(2)	(1)	(1)	(100)%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 334	$ 262	$ 72	27%
Southwest Colorado carbon dioxide production (gross)(Bcf/d)(b)	1.2	1.3	(0.1)	(8)%
Southwest Colorado carbon dioxide production (net)(Bcf/d)(b)	0.5	0.5	-	-
SACROC oil production (gross)(MBbl/d)(c)	26.9	28.9	(2.0)	(7)%
SACROC oil production (net)(MBbl/d)(d)	22.4	24.1	(1.7)	(7)%
Yates oil production (gross)(MBbl/d)(c)	21.2	21.9	(0.7)	(3)%
Yates oil production (net)(MBbl/d)(d)	9.4	9.7	(0.3)	(3)%
Katz oil production (gross)(MBbl/d)(c)	1.5	0.2	1.3	650%
Katz oil production (net)(MBbl/d)(d)	1.3	0.2	1.1	550%
Natural gas liquids sales volumes (net)(MBbl/d)(d)	9.0	8.3	0.7	8%
Realized weighted average oil price per Bbl(e)	$ 90.63	$ 68.78	$ 21.85	32%
Realized weighted average natural gas liquids price per Bbl(f)	$ 61.36	$ 60.93	$ 0.43	1%

(a) 2012 and 2011 amounts include unrealized losses of $3 million and unrealized gains of $4 million, respectively, on derivative contracts used to hedge forecast crude oil sales.

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

(c) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, and an approximately 99% working interest in the Katz Strawn unit.

(d) Net to us, after royalties and outside working interests.

(e) Includes all of our crude oil production properties.

(f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our 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.

The certain items related to unrealized gains and losses on derivative contracts described in footnote (a) to the table above accounted for a $7 million decrease in both segment earnings before depreciation, depletion and amortization expenses and revenues in the first three months of 2012, when compared with the same three months of 2011. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three month periods of 2012 and 2011, in the segment's remaining (i) $79 million (31%) increase in earnings before depreciation, depletion and amortization; and (ii) $83 million (25%) increase in operating revenues:

Three months ended March 31, 2012 versus Three months ended March 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 67	36 %	$ 69	26 %
Sales and Transportation Activities	12	17 %	11	13 %
Intrasegment eliminations	-	-	3	20 %
Total CO_2	$ 79	31 %	$ 83	25 %

The overall increase in earnings from the segment's oil and gas producing activities in the first quarter of 2012, when compared with the same period of 2011, was driven by a $63 million (30%) increase in crude oil sales revenues, increased oil production at the Katz field unit, and higher revenues from natural gas liquids sales. The increase in crude oil sales revenues was chiefly due to higher average realized sales prices for crude oil (our realized weighted average price per barrel of crude oil increased 32% in the first quarter of 2012 versus the first quarter of 2011).

The increase in crude oil sales revenues was partially offset by an almost 2% decrease in oil production volumes in the first quarter of 2012 (volumes presented in the results of operations table above), due primarily to operational delays at the SACROC field unit. The redistribution of carbon dioxide injection volumes and the balancing of reservoir pressure at SACROC are nearly complete, however, and we expect SACROC's production will increase modestly over the remaining nine months of 2012.

The increase in earnings before depreciation, depletion and amortization expenses from the segment's sales and transportation activities in the first quarter of 2012 compared to the first quarter of 2011 was largely related to higher carbon dioxide sales revenues, higher non-consent revenues, and higher crude oil pipeline transportation revenues. The increase in carbon dioxide sales revenues was due to higher average sales prices in the first quarter of 2012. The increase in non-consent revenues related to sharing arrangements pertaining to certain expansion projects completed at the McElmo Dome unit in Colorado since the end of the first quarter of 2011, and the increase in pipeline transportation revenues related to higher revenues from our Kinder Morgan Wink Texas intrastate pipeline, related chiefly to disruptions in transportation volumes during the first quarter of 2011 as a result of colder winter weather.

Terminals

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	increase/(decrease)	
	(In millions, except operating statistics and percentages)			
Revenues	$ 341	$ 332	$ 9	3%
Operating expenses(a)	(160)	(168)	8	5%
Earnings from equity investments	6	2	4	200%
Interest income and Other, net	0	1	(1)	(100)%
Income tax (expense) benefit(b)	-	7	(7)	(100)%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 187	$ 174	$ 13	7%
Bulk transload tonnage (MMtons)(c)	24.7	23.3	1.4	6%
Ethanol (MMBbl)	17.9	15.7	2.2	14%
Liquids leaseable capacity (MMBbl)	60.3	58.8	1.5	3%
Liquids utilization %	94.7 %	94.4 %	0.3 %	-

(a) 2011 amount includes (i) a combined $2 million increase in expense at our Carteret, New Jersey liquids 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) 2011 amount 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 or realize any direct benefits 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).

(c) Volumes for acquired terminals are included for both 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. We group our bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows our management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

The certain items related to our Terminals business segment and described in the footnotes to the table above accounted for a $4 million decrease in earnings before depreciation, depletion and amortization expenses in the first three months of 2012, when compared with the first quarter of 2011. Following is information related to the increases and decreases, in the comparable first three month periods of 2012 and 2011, in the segment's (i) remaining $17 million (10%) increase in earnings before depreciation, depletion and amortization; and (ii) $9 million (3%) increase in operating revenues.

Three months ended March 31, 2012 versus Three months ended March 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic	$ 9	62 %	$ 8	27 %
Gulf Liquids	4	8 %	5	9 %
Northeast	4	20 %	6	16 %
Acquired assets and businesses	4	n/a	2	n/a
Rivers	(4)	(21)%	(3)	(8)%
All others (including intrasegment eliminations and unallocated income tax expenses)	-	-	(9)	(5)%
Total Terminals	$ 17	10 %	$ 9	3 %

The overall increase in earnings before depreciation, depletion and amortization from the terminals included in our Mid-Atlantic region was driven by a $7 million increase from our Pier IX terminal, located in Newport News, Virginia. Pier IX's earnings increase was primarily due to higher export coal shipments, driven by both growth in the coal export market and by completed infrastructure expansions since the end of the first quarter of 2011.

We also benefitted from higher earnings from (i) our Pasadena and Galena Park, Texas liquids facilities located along the Houston Ship Channel (Gulf Liquids region)—due mainly to higher ethanol revenues and volumes and to higher warehousing revenues as a result of new and renewed customer agreements at higher rates; and (ii) our Carteret, New Jersey liquids terminal (Northeast region)—due primarily to tank expansion projects completed since the end of the first quarter of 2011, and to higher transfer and storage rates. Including all terminals, we increased our liquids terminals' leasable capacity by 1.5 million barrels (2.6%) since the end of the first quarter last year, primarily via completed terminal expansion projects.

The incremental earnings and revenues from acquired assets and businesses represent contributions from terminal assets and operations we acquired since the beginning of 2011. The incremental amounts represent earnings and revenues from acquired terminals' operations during the additional month of ownership in the first quarter of 2012, and do not include increases or decreases during the same months we owned the assets in 2011.

Our Terminal segment's overall increase in earnings before depreciation, depletion and amortization in the first quarter of 2012 versus the first quarter of 2011 included lower earnings from our domestic coal facilities located in the states of Illinois and Kentucky (Rivers region). The decrease in earnings related to lower coal transload volumes, due primarily to a drop in domestic demand resulting from declining or flat electrical generation, lower natural gas prices, and higher coal inventories, relative to the first quarter a year ago.

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 March 31, 2012	Three Months Ended March 31, 2011	increase/(decrease)	
	(In millions, except operating statistics and percentages)			
Revenues	$ 73	$ 76	$ (3)	(4)%
Operating expenses	(24)	(26)	2	8%
Earnings (losses) from equity investments	1	(1)	2	200%
Interest income and Other, net	3	3	-	-
Income tax expense	(3)	(4)	1	25%
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 50	$ 48	$ 2	4%
Transport volumes (MMBbl)(a)	24.9	26.7	(1.8)	(7)%

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(a) 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 each of the segment's three primary businesses, following is information related to the increases and decreases, in the comparable three month periods of 2012 and 2011, in the segment's (i) $2 million (4%) increase in earnings before depreciation, depletion and amortization; and (ii) $3 million (4%) decrease in operating revenues:

Three months ended March 31, 2012 versus Three months ended March 31, 2011

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 1	2 %	$ (3)	(4)%
Express Pipeline(a)	1	48 %	n/a	n/a
Jet Fuel Pipeline	-	-	-	-
Total Kinder Morgan Canada	$ 2	4 %	$ (3)	(4)%

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(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 first quarter periods. The slight increase in Trans Mountain's earnings was primarily due to lower income tax expenses, which fluctuate period-to-period based on both the classification of income between amounts earned by corporate subsidiaries or partnership subsidiaries, and foreign tax expenses. The slight increase in earnings from our equity investment in the Express pipeline system for the comparable three month periods related to higher net income earned by Express in the first quarter of 2012, primarily due to higher domestic volumes on Express' Platte Pipeline segment.

Other

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011		increase/(decrease)		
	(In millions, except percentages)						
General and administrative expenses(a)	$	107	$	189	$	(82)	(43)%
Interest expense, net of unallocable interest income	$	139	$	132	$	7	5%
Unallocable income tax expense	$	2	$	2	$	-	-
Net income attributable to noncontrolling interests(b)	$	2	$	3	$	(1)	(33)%

(a) 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; 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) 2011 amount includes a $1 million decrease in net income attributable to our noncontrolling interests, related to the combined effect from all of the three month 2011 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

The certain items related to our general and administrative expenses described in footnote (a) to the table above accounted for a $90 million decrease in expense in the first quarter of 2012, when compared with the first quarter of 2011. The remaining $8 million (8%) quarter-to-quarter increase in expense included increases and decreases in various operational expenses, but consisted primarily of higher employee labor, benefit and payroll tax expenses, due mainly to 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. The $7 million (5%) net increase in interest expense was due to a higher average debt balance in the first quarter of 2012. Our average borrowings for the first quarter of 2012 increased 11% from the comparable prior year period, largely due to the capital expenditures, business acquisitions, and joint venture contributions we have made since the end of the first quarter of 2011. The quarter-to-quarter increase in interest expense was partially offset, however, by a lower weighted average interest rate. The weighted average interest rate on all of our borrowings—including both short-term and long-term amounts—dropped 5% in the first quarter of 2012 versus the first quarter of 2011 (from 4.44% for the first three months of 2011 to 4.23% for the first three months of 2012).

We use interest rate swap agreements to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of both March 31, 2012 and December 31, 2011, approximately 47% of our consolidated debt balances (excluding the value of interest rate swap agreements) was subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 6 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of March 31, 2012, we had $491 million of "Cash and cash equivalents" on our consolidated balance sheet (included elsewhere in this report), an increase of $82 million (20%) from December 31, 2011. We also had, as of March 31, 2012, approximately $1.6 billion of borrowing capacity available under our $2.2 billion senior unsecured revolving credit facility (discussed below in "—Short-term Liquidity"). We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

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

In general, we expect to fund:

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

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

Credit Ratings and Capital Market Liquidity

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and expansion activities in order to maintain acceptable financial ratios. The major debt rating agencies routinely evaluate our outstanding debt, and our cost of borrowing can increase or decrease depending on these debt ratings. Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (negative) and BBB (stable), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. On October 18, 2011, in response to KMI's announcement that it had reached an agreement to purchase 100% of the outstanding stock of El Paso Corporation, Moody's revised its outlook on our long-term credit rating to negative from stable. The rating agency's revision reflected its view that the increased leverage at KMI associated with this acquisition will put additional strain on us to upstream cash to KMI. Further information about this announcement is described in Note 1 to our consolidated financial statements included elsewhere in this report.

Our short-term corporate debt credit rating is A-2 (susceptible to adverse economic conditions, however, capacity to meet financial commitments is satisfactory), Prime-2 (strong ability to repay short-term debt obligations) and F2 (good quality grade with satisfactory capacity to meet financial commitments), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. Based on these credit ratings, we expect that our short-term liquidity needs will be met primarily through borrowings under our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy pipeline and terminals industries and other financial and business factors, some of which are beyond our control.

Additionally, some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. These financial problems may arise from current global economic conditions, changes in commodity prices or otherwise. We have been and are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these customers. We cannot provide assurance that one or more of our current or future financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows; however, we have no material concentrations of credit risk and we believe we have provided adequate allowance for such customers.

Short-term Liquidity

As of March 31, 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 March 31, 2012, our credit facility was not drawn on, and as discussed above in "—General," we provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our credit facility. After reduction for (i) our outstanding borrowings under our commercial paper program; and (ii) our outstanding letters of credit, the remaining available borrowing capacity under our credit facility was $1,616 million as of March 31, 2012.

Our outstanding short-term debt as of March 31, 2012 was $891 million, primarily consisting of $500 million in principal amount of 5.85% senior notes that mature September 15, 2012, and $358 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.

We had a working capital surplus of $1,544 million as of March 31, 2012 and a working capital deficit of $1,543 million as of December 31, 2011. The overall $3,087 million (200%) favorable change from year-end 2011 was primarily due to (i) our reclassification, at estimated fair value, of the March 31, 2012 net assets of our FTC Natural Gas Pipelines disposal group as current assets and liabilities held for sale (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 March 31, 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 first quarter 2012 equity issuances, see Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. Our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate senior notes provide that we may redeem the notes at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make-whole premium.

As of March 31, 2012 and December 31, 2011, the net carrying value of the various series of our senior notes was $12,574 million and $12,026 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $115 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 quarter of 2012, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report. For additional information regarding our debt securities, see Note 8 "Debt" to our consolidated financial statements included in our 2011 Form 10-K.

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

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, financing our expansion capital expenditures and acquisitions with approximately 50% equity and 50% debt. In the short-term, we fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable interest rates. We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset, and for the comparable first quarter periods of 2012 and 2011, our sustaining capital expenditures totaled $44 million and $36 million, respectively. These amounts included $2 million and $1 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 quarter 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 $194 million for sustaining capital expenditures for the remaining nine months of 2012. This amount includes (i) $9 million for our proportionate share of our equity investees' forecasted sustaining capital expenditures (including Rockies Express, which is included in our FTC Natural Gas Pipelines disposal group); and (ii) $15 million for the assets, excluding Rockies Express, included in our FTC Natural Gas Pipelines disposal group.

Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Rockies Express, Midcontinent Express and Fayetteville Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, with proceeds from issuing their own long-term notes, or with proceeds from contributions received from their member owners. We have no contingent debt obligations with respect to Rockies Express, Midcontinent Express, or Fayetteville Express. For information on our contingent debt obligations, see Note 4 "Debt—Contingent Debt" to our consolidated financial statements included elsewhere in this report.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. Our discretionary capital expenditures totaled $311 million in the first quarter of 2012, and $230 million in the first quarter of 2011. The quarter-to-quarter increase in discretionary capital expenditures was primarily due to higher investment undertaken in the first quarter of 2012 to expand and improve our Products Pipelines and Natural Gas

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. We have forecasted $1.26 billion for discretionary capital expenditures for the remaining nine months of 2012. This amount does not include forecast discretionary expenditures by our equity investees, forecast capital contributions to our equity investees, or forecast expenditures for asset acquisitions.

Operating Activities

Net cash provided by operating activities was $658 million for the three months ended March 31, 2012, versus $521 million in the same comparable period of 2011. The quarter-to-quarter increase of $137 million (26%) in cash flow from operations primarily consisted of the following:

- a $102 million increase in cash from overall higher partnership income—after adjusting our quarter-to-quarter $133 million decrease in net income for the following four non-cash items: (i) a $322 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 $25 million increase due to higher non-cash depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); (iii) a $90 million decrease due to certain higher non-cash compensation expenses allocated to us from KMI in the first quarter of 2011 (as discussed in Note 9 "Related Party Transactions—Non-Cash Compensation Expenses" to our consolidated financial statements included elsewhere in this report, we do not have any obligation, nor did we pay any amounts related to these allocated expenses); and (iv) a $22 million decrease due to higher earnings from equity investees. The quarter-to-quarter 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 $63 million increase in cash attributable to payments made in March 2011 for transportation rate settlements on our Pacific operations' refined products pipelines; and

- a combined $43 million decrease in cash related to net changes in working capital items, non-current assets and liabilities, and other non-cash income and expense items. The decrease related primarily to both unfavorable changes in cash from the collection and payment of trade and related party receivables and payables (including collections and payments on natural gas transportation and exchange imbalance receivables and payables) and incremental expenditures for short-term liquids transmix inventories.

Investing Activities

Net cash used in investing activities was $373 million for the three month period ended March 31, 2012, compared to $230 million used in the comparable 2011 period. The $143 million (62%) decrease in cash in the first three months of 2012 due to higher cash expended for investing activities was primarily attributable to:

- an $88 million decrease in cash due to higher capital expenditures, as described above in "—Capital Expenditures;"

- a $36 million decrease in cash due to lower capital distributions (distributions in excess of cumulative earnings) received from equity investments in the first quarter of 2012—chiefly due to lower capital distributions received from Rockies Express Pipeline LLC;

- a $27 million decrease in cash due to higher contributions in the first quarter of 2012 to our 25%-owned EagleHawk Field Services LLC. EagleHawk used the contributions as partial funding for natural gas gathering and treating infrastructure expansions;

- a $27 million decrease in cash related to net changes in margin and restricted deposits, due primarily to the January 2011 release of $50 million in cash previously restricted for our investment in Watco (described below); and

- a $36 million increase in cash due to lower acquisitions of assets and investments. In the first quarter 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 three months of 2011, we spent a combined $66 million for investment acquisitions, consisting of $50 million for an initial preferred equity interest in Watco Companies, LLC, and $16 million for a 50% ownership interest in Deeprock North, LLC.

Financing Activities

Net cash used in financing activities amounted to $210 million for the first quarter of 2012, and $244 million for the first quarter of 2011. The $34 million (14%) overall increase in cash due to lower cash expended for financing activities consisted of the following:

- a $43 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 combined $151 million increase due to higher net issuances of our senior notes (in the first quarter of 2012 and 2011, we generated net proceeds of $544 million and $393 million, respectively, from both issuing and repaying senior notes); and (ii) a $108 million decrease due to higher net repayments of short-term borrowings under our commercial paper program;

- a $43 million increase in cash due to higher partnership equity issuances. The increase reflects the $124 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first three months of 2012 (discussed in Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report), versus the $81 million we received from the sales of additional common units in the first three months a year ago. In both quarters, we used the proceeds from our equity issuances to reduce the borrowings under our commercial paper program; and

- a $52 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 $590 million in the first quarter of 2012. In the comparable quarter of 2011, we distributed $538 million to our partners. Further information regarding our distributions is discussed following in "—Partnership Distributions;"

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. Our 2011 Form 10-K contains 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.

On February 14, 2012, we paid a quarterly distribution of $1.16 per unit for the fourth quarter of 2011. This distribution was 3% greater than the $1.13 distribution per unit we paid on February 14, 2011 for the fourth quarter of 2010. We paid this distribution in cash to our general partner, our common unitholders, and our sole Class B unitholder. KMR, our sole i-unitholder, received additional i-units based on the $1.16 cash distribution per common unit.

The incentive distribution that we paid on February 14, 2012 to our general partner (for the fourth quarter of 2011) totaled $302 million, and the incentive distribution that we paid in February 2011 (for the fourth quarter of 2010) totaled $275 million. The increase in the incentive distribution paid to our general partner for the fourth quarter of 2011 versus the fourth quarter of 2010 reflects the increase in the distribution 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 $8 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.

Furthermore, on April 18, 2012, we declared a cash distribution of $1.20 per unit for the first quarter of 2012 (an annualized rate of $4.80 per unit). This distribution is 5% higher than the $1.14 per unit distribution we made for the first quarter of 2011. For more information about our first quarter 2012 and first quarter 2011 cash distributions, see Note 5 "Partners' Capital—Subsequent Event" to our consolidated financial statements included elsewhere in this report.

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 (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 neutral to our distribution per unit in 2012 and 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 $103.72 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.

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.

Recent Accounting Pronouncements

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

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- the terms of our sales of assets as mandated by the FTC or of drop-downs of assets to us from KMI;
- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal, steel and other bulk materials and chemicals in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, California Public Utilities Commission, Canada's National Energy Board or another regulatory agency;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains, areas of shale gas formation and the Alberta oil sands;

- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting standards that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, accidents, sabotage, terrorism (including cyber terrorism) or other similar acts impacting our operations or otherwise causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells;
- the uncertainty inherent in estimating future oil and natural gas production or reserves that we may experience;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 10 to our consolidated financial statements included elsewhere in this report.

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

See 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 these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in 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 the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 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. For more information on our risk management activities, see Note 6 “Risk Management” to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of March 31, 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 March 31, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

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

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 planned acquisition of El Paso, KMI has agreed to divest the assets comprising our FTC Natural Gas Pipelines disposal group. As a result of this agreement, we reduced the disposal group's net asset carrying value to its estimated fair value and recognized a $322 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.

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

Effective March 14, 2012, we issued 87,162 common units as part of the purchase price for certain petroleum coke terminal assets that we acquired from TGS Development, L.P. on June 10, 2011. The total purchase price for the acquired assets was $74 million, consisting of $43 million in cash, $24 million in common units, and an obligation to pay additional consideration of $7 million approximately one year from the closing date. On March 14, 2012, we settled the $7 million liability by issuing additional common units. 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 — Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.95% Senior Notes due September 1, 2022.

4.2 — Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4)

(iii) (A) of Regulation S-K (17 CFR 229.601). Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

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 months ended March 31, 2012 and 2011; (ii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2012 and 2011; (iii) our Consolidated Balance Sheets as of March 31, 2012 and December 31, 2011; (iv) our Consolidated Statements of Cash Flows for the three months ended March 31, 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: April 27, 2012

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