ROYAL GOLD INC
Form 10-K
August 26, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the Fiscal Year Ended June 30, 2010

or

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

For the Transition Period From to
Commission File Number 001-13357

Royal Gold, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**84-0835164** (I.R.S. Employer Identification No.)
1660 Wynkoop Street, Suite 1000 **Denver, Colorado** (Address of Principal Executive Offices)	**80202** (Zip Code)

Registrant's telephone number, including area code: (303) 573-1660

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

Title of Each Class	**Name of Each Exchange on Which Registered**
Common stock, $0.01 par value	NASDAQ Global Select Market

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

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

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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "accelerated filer", "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

(Check one):	Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant, based upon the closing sale price of Royal Gold common stock on December 31, 2009, as reported on the NASDAQ Global Select Market was $1,794,606,869. There were 53,671,158 shares of the Company's common stock, par value $0.01 per share, outstanding as of August 24, 2010. In addition, as of such date, there were 1,610,464 exchangeable shares of RG Exchangeco Inc., a subsidiary of registrant, outstanding which are exchangeable at any time into shares of the Company's common stock on a one-for-one basis and entitle their holders to dividend and other rights economically equivalent to those of the Company's common stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2010 Annual Meeting of Stockholders scheduled to be held on November 17, 2010, and to be filed within 120 days after June 30, 2010, are incorporated by reference into Part III, Items 10, 11, 12, 13 and 14 of this Annual Report on Form 10-K.

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This document (including information incorporated herein by reference) contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, which involve a degree of risk and uncertainty due to various factors affecting Royal Gold, Inc. and its subsidiaries. For a discussion of some of these factors, see the discussion in Item 1A, Risk Factors, of this report. In addition, please see our note about forward-looking statements included in Item 7, Management's Discussion and Analysis of Consolidated Financial Condition and Results of Operations ("MD&A"), of this report.

PART I

ITEM 1. BUSINESS

Overview

Royal Gold, Inc. ("Royal Gold", the "Company", "we", "us", or "our"), together with its subsidiaries, is engaged in the business of acquiring and managing precious metals royalties and similar interests derived from production. Royalties are passive (non-operating) interests in mining projects that entitle the Company to a portion of the revenue or production from the project after deducting specified costs, if any. We seek to acquire existing royalties or to finance projects that are in production or in development stage in exchange for royalty interests. We are engaged in a continual review of opportunities to acquire existing royalties, to create new royalties through the financing of mine development or exploration, or to acquire companies that hold royalties. We currently, and generally at any time, have acquisition opportunities in various stages of active review, including, for example, our engagement of consultants and advisors to analyze particular opportunities, analysis of technical, financial and other confidential information, submission of indications of interest, participation in preliminary discussions and involvement as a bidder in competitive auctions.

As of June 30, 2010, the Company owns royalties on 33 producing properties, 23 development stage properties and over 130 exploration stage properties, of which the Company considers 37 to be evaluation stage projects.32 producing properties. The Company uses "evaluation stage" to describe exploration stage properties that contain mineralized material and on which operators are engaged in the search for reserves. We do not conduct mining operations nor are we required to contribute to capital costs, exploration costs, environmental compliance costs or other operating costs on the properties in which we hold royalty interests. During the fiscal year ended June 30, 2010, we focused on the management of our existing royalty interests, the acquisition of royalty interests, the acquisition and integration of International Royalty Corporation ("IRC"), and the creation of royalty and similar interests through financing and strategic exploration alliances.

As discussed in further detail throughout this report, some significant developments to our business during fiscal year 2010 were as follows:

(1) Our royalty revenues increased 85% to $136.6 million, compared with $73.8 million during fiscal year 2009;

(2) On January 25, 2010, we acquired an interest in the gold produced from the sulfide portion of the Andacollo project in Chile ("Andacollo Royalty") for $217.9 million in cash and 1,204,136 shares of our common stock (valued at approximately $53.4 million on the date of acquisition);

(3) On February 22, 2010, we, through RG Exchangeco Inc. (formerly known as 7296355 Canada Ltd.), a wholly-owned Canadian subsidiary of Royal Gold ("RG Exchangeco") acquired all of the issued and outstanding common shares of IRC, a company incorporated in Canada (the "IRC Transaction"). The purchase price for the IRC Transaction consisted of approximately $350.0 million in cash, 5,234,086 shares of Royal Gold common stock (valued at $230.4 million on the date of acquisition) and 1,806,649 exchangeable shares of

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RG Exchangeco (valued at $79.5 million on the date of acquisition) that are exchangeable at any time into shares of our common stock on a one-for-one basis ("Exchangeable Shares");

(4) In June 2010, we sold 5,980,000 shares of our common stock, at a price of $48.50 per share, resulting in net proceeds to us of approximately $276.2 million; and

(5) We increased our calendar year dividend to $0.36 per basic share, which is paid in quarterly installments throughout calendar year 2010. This represents a 12.5% increase compared with the dividend paid during calendar year 2009.

Certain Definitions

Additional Mineralized Material: Additional mineralized material is that part of a mineral system that has potential economic significance but cannot be included in the proven and probable ore reserve estimates until further drilling and metallurgical work is completed, and until other economic and technical feasibility factors based upon such work have been resolved. The Securities and Exchange Commission (the "SEC") does not recognize this term. Investors are cautioned not to assume that any part or all of the mineral deposits in these categories will ever be converted into reserves.

Gross Proceeds Royalty (GPR): A royalty in which payments are made on contained ounces rather than recovered ounces.

Gross Smelter Return (GSR) Royalty: A defined percentage of the gross revenue from a resource extraction operation, in certain cases reduced by certain contract-defined costs paid by or charged to the operator.

g/t: A unit representing grams per tonne.

Net Profits Interest (NPI): A defined percentage of the gross revenue from a resource extraction operation, after recovery of certain contract-defined pre-production costs, and after deduction of certain contract-defined mining, milling, processing, transportation, administrative, marketing and other costs.

Net Smelter Return (NSR) Royalty: A defined percentage of the gross revenue from a resource extraction operation, less a proportionate share of incidental transportation, insurance, refining and smelting costs.

Net Value Royalty (NVR): A defined percentage of the gross revenue from a resource extraction operation, less certain contract-defined transportation costs, milling costs and taxes.

Proven (Measured) Reserves: Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes, and the grade is computed from the results of detailed sampling, and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that the size, shape, depth and mineral content of the reserves are well established.

Probable (Indicated) Reserves: Reserves for which the quantity and grade are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance of probable (indicated) reserves, although lower than that for proven (measured) reserves, is high enough to assume geological continuity between points of observation.

Payable Metal: Ounces or pounds of metal in concentrate payable to the operator after deduction of a percentage of metal in concentrate that is paid to a third-party smelter pursuant to smelting contracts.

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Reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Royalty: The right to receive a percentage or other denomination of mineral production from a resource extraction operation.

Ton: A unit of weight equal to 2,000 pounds or 907.2 kilograms.

Tonne: A unit of weight equal to 2,204.6 pounds or 1,000 kilograms.

Our Producing Royalty Interests

Our producing royalty interests on mines that were in production and generated revenue for the Company during all or part of fiscal year 2010 are shown in the following table. The number of properties listed here as production stage could change periodically due to developments at the properties. Please see Item 2, Properties, of this report for further discussion of our principal producing royalty interests.

Mine	Location	Operator	Royalty (Gold unless otherwise stated)
Cortez	Nevada, USA	Barrick Gold Corporation ("Barrick")	GSR1: 0.40%-5.0% sliding-scale GSR GSR2: 0.40%-5.0% sliding-scale GSR GSR3: 0.71% GSR NVR1: 0.39% NVR
Robinson	Nevada, USA	QuadraFNX Mining Ltd. ("Quadra")	3.0% NSR (copper, gold, silver, molybdenum)
Leeville	Nevada, USA	Newmont Mining Corporation ("Newmont")	1.8% NSR
Goldstrike	Nevada, USA	Barrick	0.9% NSR
Bald Mountain	Nevada, USA	Barrick	1.75%-3.5% sliding-scale NSR
Twin Creeks	Nevada, USA	Newmont	2.0% GPR
Wharf	South Dakota, USA	Goldcorp Inc. ("Goldcorp")	0.0%-2.0% sliding-scale NSR
Skyline(1)	Utah, USA	Arch Coal, Inc.	1.41% GOR
Dolores	Chihuahua, Mexico	Minefinders Corporation, Ltd. ("Minefinders")	3.25% NSR; 2.0% NSR (silver)
El Chanate(2)	Sonora, Mexico	Capital Gold Corporation	2.0%-4.0% sliding-scale NSR
Mulatos(3)	Sonora, Mexico	Alamos Gold, Inc. ("Alamos")	1.0%-5.0% sliding-scale NSR
Peñasquito(4)	Zacatecas, Mexico	Goldcorp	2.0% NSR (gold, silver, lead, zinc)
Las Cruces(1)	Andalucía, Spain	Inmet Mining ("Inmet")	1.5% NSR (copper)
Taparko(5)	Namantenga, Burkina Faso	High River Gold Mines Ltd. ("High River")	15% GSR (TB-GSR1); 0%-10% sliding-scale GSR (TB-GSR2)
Inata(1)	Soum, Burkina Faso	Avocet Mining PLC	2.5% NSR
Siguiri(6)	Kankan, Guinea	AngloGold Ashanti Limited	0.0%-1.875% sliding-scale NSR

Martha	Santa Cruz Province, Argentina	Coeur d'Alene Mines Corporation	2.0% NSR (gold and silver)
Don Mario	Chiquitos Province, Bolivia	Orvana Minerals Corp.	3.0% NSR

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Mine	Location	Operator	Royalty (Gold unless otherwise stated)
Andacollo(7)	Region IV, Chile	Compañía Minera Teck Carmen de Andacollo ("CDA")	75% of gold produced
El Toqui	Region XI, Chile	Breakwater Resources	1.0%-3.0% sliding-scale NSR (gold, lead and zinc)
Voisey's Bay(1)	Labrador, Canada	Vale Ltd. ("Vale")	2.7% NSR (nickel, copper, cobalt)
Williams	Ontario, Canada	Barrick	0.97% NSR
Allan	Saskatchewan, Canada	Potash Corporation of Saskatchewan	$0.36-$1.44 per ton sliding-scale; $0.25 per ton (potash)
El Limon	El Limon, Nicaragua	B2Gold Corp. (95%) and Inversiones Mineras S.A. (5%)	3.0% NSR
Balcooma	Queensland, Australia	Kagara Ltd.	1.5% NSR (gold, silver, lead, copper and zinc)
Gwalia Deeps(1)	Western Australia, Australia	St. Barbara Limited ("St. Barbara)	1.5% NSR
Mt. Goode (Cosmos South)	Western Australia, Australia	Xstrata PLC	1.5% NSR (nickel)
South Laverton(1)	Western Australia, Australia	Saracen Mineral Holdings Limited	1.5% NSR
Southern Cross(1)	Western Australia, Australia	St. Barbara	1.5% NSR

(1) Royalty acquired as part of the IRC transaction as discussed within Item 7, MD&A, of this report. Three oil and gas royalty interests, not shown here, were also acquired as part of the IRC transaction.

(2) Royalty is capped once payments of approximately $17.0 million have been received. As of June 30, 2010, approximately $12.4 million remains under the cap.

(3) Royalty is capped at 2.0 million gold ounces of production. Approximately 581,000 cumulative ounces of gold have been produced as of June 30, 2010.

(4) The Peñasquito project consists of oxide and sulfide ores, each processed by different methods. The sulfide portion began production during the fourth quarter of calendar 2009.

(5) TB-GSR1 will remain in effect until cumulative production of 804,420 ounces of gold is achieved or until cumulative payments of $35.0 million have been made to Royal Gold, whichever occurs first. TB-GSR2 will remain in effect until the termination of TB-GSR1. As of June 30, 2010, we have recognized approximately $30.6 million in royalty revenue associated with TB-GSR1, which is attributable to cumulative production of 202,000 ounces of gold. Management expects the dollar cap could be reached during the third quarter of calendar year 2010.

(6) Royalty is subject to a dollar cap of approximately $12.0 million. As of June 30, 2010, approximately $1.8 million remains under the cap. Management expects the cap could be reached sometime during the last half of calendar 2010.

(7) Production at Andacollo began during the second quarter of calendar 2010. The royalty is 75% of the gold produced from the sulfide portion of the deposit until 910,000 payable ounces have been sold and 50% of the gold produced in excess of 910,000 payable gold ounces.

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Our Development Stage Royalty Interests

We own royalty interests that are currently in development stage. We categorize development stage royalties as properties that are not yet in production or not yet generating revenue for the Company. Please see Item 2, Properties, of this report for further discussion on our principal development stage royalty interests.

The following royalty interests are currently in development stage because they have not yet provided revenue to the Company. These royalties are associated with properties currently in production.

Mine	Location	Operator	Royalty (Gold unless otherwise stated)
Marigold(1)	Nevada, USA	Goldcorp	2.0% NSR
Troy(2)	Montana, USA	Revett Minerals, Inc.	3.0% GSR (silver and copper)
Taparko	Burkina Faso, West Africa	High River	2.0% GSR (TB-GSR3); 0.75% milling royalty (TB-MR1)
Avebury(3)	Tasmania, Australia	Minerals and Metals Group	2% NSR (nickel)
Koolanooka	Western Australia, Australia	Sinosteel Midwest Corporation Ltd.	AUD$0.25 per ton (iron ore fines)
Meekatharra(3) (Yaloginda)	Western Australia, Australia	Mercator Gold PLC	0.45% NSR
Reedy's Burnakura(4)	Western Australia, Australia	Jinka Metals Ltd.	1.5%-2.5% NSR

(1) Our royalty interest on the Marigold mine covers the majority of six sections of land, containing a number of open pits, but does not cover the current mining in the Basalt/Antler area. Approximately 45% of the current Marigold reserves are covered by this royalty.

(2) Royalty became effective July 1, 2010.

(3) Royalty acquired as part of the IRC transaction, as discussed below within Item 7, MD&A, of this report.

(4) Royalty becomes payable after 300,000 gold ounces have been produced from the property. After an additional 75,000 gold ounces have been produced from the property, the royalty rate increases from a 1.5% NSR to a 2.5% NSR.

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The following royalty interests are currently in development stage because the properties are being developed by their operators but are not yet in production.

Mine	Location	Operator	Royalty (Gold unless otherwise stated)
Soledad Mountain(1)	California, USA	Golden Queen Mining Co. Ltd.	3.0% NSR (gold and silver)
Gold Hill(2)	Nevada, USA	Kinross Gold Corporation (50%), Barrick (50%)	1.0% to 2.0% sliding-scale NSR and 0.9% NSR (MACE claims)
Relief Canyon	Nevada, USA	Firstgold Incorporated	3.0% NSR and 1.0% NSR
Pascua-Lama(2,3)	Region III, Chile	Barrick	0.67% to 4.48% sliding-scale NSR and 1.05% fixed rate royalty (copper)
Bundarra(1)	Western Australia, Australia	Terrain Minerals Ltd.	1.5% NSR
Meekatharra(2) (Paddy's Flat)	Western Australia, Australia	Mercator Gold	A$10.00 per gold ounce produced and 1.5% NSR
Tarmoola(1)	Western Australia, Australia	St. Barbara	1.5% NSR
Schaft Creek(1)	British Columbia, Canada	Copper Fox Metals Inc.	3.5% NPI (gold, silver, copper, molybdenum)
Pine Cove	Newfoundland, Canada	New Island Resources Inc. (70%), Anaconda Mining Inc. (30%)	7.5% NPI
Rambler North	Newfoundland, Canada	Rambler Metals and Mining PLC	1.0% NSR
Holt(4)	Ontario, Canada	St Andrew Goldfields Ltd. ("St Andrew")	0.00013 × quarterly average gold price
Caber(1)	Quebec, Canada	Breakwater Resources Ltd.	1.0% NSR (copper, zinc)
Canadian Malartic(5)	Quebec, Canada	Osisko Mining Corporation ("Osisko")	2.0% to 3.0% sliding-scale NSR
Wolverine(1)	Yukon, Canada	Yukon Zinc Corporation ("Yukon Zinc")	0.00% to 9.45% sliding-scale NSR (gold and silver)
Lluvia deOro(6)	Sonora, Mexico	NWM Mining Corp.	4.0% NSR
Tambor(1)	South-Central, Guatemala	Radius Gold Inc.	4.0% NSR

(1) Royalty acquired as part of the IRC Transaction, as discussed below within Item 7, MD&A, of this report.

(2) A portion of the royalty was acquired as part of the IRC Transaction, as discussed below within Item 7, MD&A, of this report.

(3) See "Recent Developments, Business Developments" within Item 7, MD&A, of this report for a further discussion on recent developments at Pascua-Lama.

(4) See "Recent Developments, Property Developments" within Item 7, MD&A, of this report for a further discussion on recent developments at Holt.

(5) The royalty is subject to a buy-down right for $1.0 to $1.5 million. If the buy-down right is exercised by Osisko, the sliding-scale NRS would be reduced to range between 1.0% and 1.5%.

(6) The various parties claiming interest in the mining concessions subject to this royalty have disputed any royalty obligation.

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Our Exploration Stage Royalty Interests

We own royalty interests on over 130 exploration stage projects on six continents. None of our exploration stage projects contain proven and probable reserves as of December 31, 2009, as determined by the owner or operator of such projects.

Our Operational Information

Financial Information about Geographic Areas

Royal Gold's royalty revenue and long-lived assets (royalty interests in mineral properties, net) are geographically distributed as shown in the following table. Please refer to Item 2, Properties, for further discussion of our principal royalty interests on producing mineral properties.

	Royalty Revenue Fiscal Year Ended June 30,			Royalty Interests in Mineral Property, net Fiscal Year Ended June 30,		
	2010	2009	2008	2010	2009	2008
United States	40%	56%	79%	5%	13%	18%
Africa(1)	29%	21%	11%	2%	8%	12%
Mexico	15%	15%	4%	13%	45%	55%
Australia	5%	2%		6%	6%	
Canada	4%	2%	1%	27%	19%	1%
Chile	4%	1%		42%	6%	7%
Other	3%	3%	5%	5%	3%	7%

(1) Consists of royalties on properties in Burkina Faso and Guinea.

Our financial results are primarily tied to the price of gold, silver, copper and other metals, as well as production from our producing royalty interests. For the fiscal years ended June 30, 2010, 2009 and 2008, gold, silver and copper price averages and percentage of royalty revenues by metal were as follows:

	Fiscal Year Ended					
	June 30, 2010		June 30, 2009		June 30, 2008	
Metal	Average Price	Percentage of Royalty Revenue	Average Price	Percentage of Royalty Revenue	Average Price	Percentage of Royalty Revenue
Gold ($/ounce)	$ 1,089	81%	$ 874	84%	$ 821	74%
Silver ($/ounce)	$ 16.85	3%	$ 12.91	3%	$ 15.40	3%
Copper ($/pound)	$ 3.03	9%	$ 2.25	11%	$ 3.53	23%
Other	N/A	7%	N/A	2%	N/A	0%

Our financial results are discussed in further detail within Part II, Item 7, MD&A, and within our audited consolidated financial statements which are included in Part II, Item 8, Financial Statements and Supplementary Data. The risks associated with the operations of our royalty interests in various geographic regions are discussed in Item 1A, Risk Factors.

Competition

The mining industry in general and the royalty segment in particular are competitive. We compete with other royalty companies, mine operators and financial buyers in efforts to acquire existing royalties and with the lenders and investors providing debt and equity financing to operators of mineral properties in our efforts to create new royalties. Many of our competitors in the lending and mining business are larger than we are and have greater resources and access to capital than we have. Key

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competitive factors in the royalty acquisition and financing business include price, structure and access to capital.

Regulation

Like all mining operations, the operators of the mines that are subject to our royalties must comply with environmental laws and regulations promulgated by federal, state and local governments including, but not limited to, the National Environmental Policy Act; the Comprehensive Environmental Response, Compensation and Liability Act; the Clean Air Act; the Clean Water Act; the Hazardous Materials Transportation Act; and the Toxic Substances Control Act. Mines located on public lands in the United States are subject to the General Mining Law of 1872 and are subject to comprehensive regulation by either the United States Bureau of Land Management (an agency of the United States Department of the Interior) or the United States Forest Service (an agency of the United States Department of Agriculture). The mines also are subject to regulations of the United States Environmental Protection Agency ("EPA"), the United States Mine Safety and Health Administration and similar state and local agencies. Operators of mines that are subject to our royalties in other countries are obligated to comply with similar laws and regulations in those jurisdictions. Although we are not responsible as a royalty owner for ensuring compliance with these laws and regulations, failure by the operators of the mines on which we have royalties to comply with applicable laws, regulations and permits can result in injunctive action, damages and civil and criminal penalties on the operators which could reduce or eliminate production from the mines and thereby reduce or eliminate the royalties we receive and negatively affect our financial condition.

Corporate Information

We were incorporated under the laws of the State of Delaware on January 5, 1981. Our executive offices are located at 1660 Wynkoop Street, Suite 1000, Denver, Colorado 80202; our telephone number is (303) 573-1660.

Available Information

Royal Gold maintains an internet website at www.royalgold.com. Royal Gold makes available, free of charge, through the Investor Relations section of its website, its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after such material is electronically filed with the SEC. Our SEC filings are available from the SEC's internet website at www.sec.gov which contains reports, proxy and information statements and other information regarding issuers that file electronically. These reports, proxy statements and other information may also be inspected and copied at the public reference facilities maintained by the SEC at 100 F Street, NE, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facilities. The charters of Royal Gold's key committees of the Board of Directors and Royal Gold's Code of Business Conduct and Ethics are also available on the Company's website. Any of the foregoing information is available in print to any stockholder who requests it by contacting Royal Gold's Investor Relations Department at (303) 573-1660.

Company Personnel

We currently have 20 employees, all of whom are located in Denver, Colorado. Our employees are not subject to a labor contract or a collective bargaining agreement. We consider our employee relations to be good.

We also retain independent contractors to provide consulting services, relating primarily to geologic and geophysical interpretations and also relating to such metallurgical, engineering, and other technical matters as may be deemed useful in the operation of our business.

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ITEM 1A. RISK FACTORS

You should carefully consider the risks described below before making an investment decision. Our business, financial condition, results of operations and cash flows could be materially adversely affected by any of these risks. The market or trading price of our securities could decline due to any of these risks. In addition, please see our note about forward-looking statements included in Part II, Item 7, MD&A, of this report. Please note that additional risks not presently known to us or that we currently deem immaterial may also impair our business and operations.

Risks Related to Our Business

We own passive interests in mining properties, and it is difficult or impossible for us to ensure properties are operated in our best interest.

All of our current revenue is derived from royalties on properties operated by third parties. The holder of a royalty interest typically has no authority regarding the development or operation of a mineral property. Therefore, we are not in control of decisions regarding development or operation of any of the properties on which we hold a royalty interest, and we have limited or no legal rights to influence those decisions.

Our strategy of having others operate properties on which we retain a royalty or other passive interest puts us generally at risk for the decisions of others regarding all operating matters, including permitting, feasibility analysis, mine design and operation, processing, plant and equipment matters and temporary or permanent suspension of operations, among others. These decisions are likely to be motivated by the best interests of the operator rather than to maximize royalties. Although we attempt to secure contractual rights, such as audit or access rights, when we create new royalties that will permit us to protect our interests, there can be no assurance that such rights will always be available or sufficient, or that our efforts will be successful in achieving timely or favorable results or in affecting the operation of the properties in which we have royalty interests in ways that would be beneficial to our stockholders.

Volatility in gold, silver, copper and other metal prices may have an adverse impact on the value of our royalty interests and reduce our royalty revenues. Certain of our royalty contracts have features that may amplify the negative effects of a drop in commodity prices.

The profitability of our royalty interests is directly related to the market price of gold, silver, copper and other metal prices. The market price of each metal may fluctuate widely and is affected by numerous factors beyond the control of any mining company. These factors include metal supply, industrial and jewelry fabrication and investment demand, expectations with respect to the rate of inflation, the relative strength of the U.S. dollar and other currencies, interest rates, gold sales and loans by central banks, forward sales by metal producers, global or regional political, economic or banking crises and a number of other factors. If gold, copper and certain other metal prices drop dramatically, we might not be able to recover our initial investment in royalty interests or properties. Moreover, the selection of a royalty investment or of a property for exploration or development, the determination to construct a mine and place it into production, and the dedication of funds necessary to achieve such purposes are decisions that must be made long before the first revenues from production will be received. Price fluctuations between the time that decisions about exploration, development and construction are made and the commencement of production can have a material adverse effect on the economics of a mine and can eliminate or have a material adverse impact on the value of royalty interests.

Furthermore, if the market price of gold, copper or certain other metals should drop, then our royalty revenues would also drop. Our sliding-scale royalties, such as those at Cortez, Taparko, Mulatos and other properties, amplify this effect. When the gold price falls below a certain mark in a sliding-scale royalty, we receive a lower royalty rate on production. In addition, certain royalty agreements, such as our royalty agreement for the Robinson mine and the Peñasquito mine are based on the operator's concentrate sales to smelters, which include price adjustments between the operator and the smelter based on commodity prices at a later date, three to four months in the case of Robinson. In such cases, our royalty payments from the operator include a component of these later adjustments, which can result in decreased royalty revenue in later periods if commodity prices have fallen.

Volatility in gold, silver and copper prices is demonstrated by the annual high and low prices for those metals from selected years during the past decade. High and low gold prices per ounce, based on the London Bullion Market Association P.M. fix, have ranged from $293 to $256 in 2001, from $537 to $411 in 2005, from $1212 to $810 in 2009, and from $1,261 to $1,058 year to date. High and low silver prices per ounce, based on the London Bullion Market Association P.M. fix, have ranged from $4.82 to $4.07 in 2001, from $9.23 to $6.39 in 2005, from $19.18 to $10.51 in 2009, and from $19.64 to $15.14 year to date. High and low cooper prices per pound, based on the London Metal Exchange cash settlement price for copper Grade A, have ranged from $0.81 to $0.62 in 2001, from $2.08 to $1.44 in 2005, from $3.33 to $1.38 in 2009, and from $3.61 to $2.76 year to date.

Our revenues are subject to operational and other risks faced by operators of our mining properties.

Although we are not required to pay capital costs or operating costs, our financial results are indirectly subject to hazards and risks normally associated with developing and operating mining properties where we hold royalty interests. These risks include:

- insufficient ore reserves;
- fluctuations in production costs incurred by operators or third parties that may make mining of ore uneconomical or impact the amount of reserves;
- declines in the price of gold and other metals;
- mine operating and ore processing facility problems;
- economic downturns and operators' insufficient financing;
- significant environmental and other regulatory permitting requirements and restrictions and any changes thereto;
- challenges by non-mining interests to existing permits and mining rights, and to applications for permits and mining rights;
- community unrest, labor disputes or work stoppages at mines;
- geological problems;
- pit wall or tailings dam failures or any underground stability issues;
- natural catastrophes such as floods or earthquakes;

- the risk of injury to persons, property or the environment; and
- uncertain foreign political and economic environments.

Operating cost increases can have a negative effect on the value of and income from our royalty interests by potentially causing an operator to curtail, delay or close operations at a mine site.

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Acquired royalty interests, particularly on development stage properties, are subject to the risk that they may not produce anticipated royalty revenues.

The royalty interests we acquire may not produce the anticipated royalty revenues. Royalty interests acquired on development stage properties are particularly sensitive to this risk. The success of our royalty acquisitions is based on our ability to make accurate assumptions regarding the valuation, timing and amount of royalty payments, particularly with respect to acquisitions of royalties on development stage properties. If the operator does not bring the property into production and operate in accordance with feasibility studies, technical or reserve reports or other plans, then acquired royalty interests may not yield sufficient royalty revenues to be profitable. Furthermore, operators of development stage properties must obtain all necessary environmental permits and access to water, power and other raw materials needed for operations in order to begin production, and there can be no assurance operators will be able to do so. Pascua-Lama in Chile, the Canadian Malartic, Holt and Wolverine mining projects in Canada, are among our principal development stage royalty acquisitions to date. The failure of any of these projects to produce anticipated royalty revenues may materially and adversely affect our financial condition and results of operations.

We depend on our operators for the calculation of royalty payments. We may not be able to detect errors amd payment calculations may call for retroactive adjustments.

Our royalty payments are calculated by the operators of the properties on which we have royalties based on their reported production. Each operator's calculation of our royalty payments is subject to and dependent upon the adequacy and accuracy of its production and accounting functions, and errors may occur from time to time in the calculations made by an operator. For example, the complex nature of mining and ownership of mining interests can result in errors regarding allocation of production, such as those that occurred in connection with our restatement of our consolidated financial statements for fiscal 2008. Certain royalty agreements require the operators to provide us with production and operating information that may, depending on the completeness and accuracy of such information, enable us to detect errors in the calculation of royalty payments that we receive. We do not, however, have the contractual right to receive production information for all of our royalty interests. As a result, our ability to detect royalty payment errors through our royalty monitoring program and its associated internal controls and procedures is limited, and the possibility exists that we will need to make retroactive royalty revenue adjustments. Some of our royalty contracts provide us the right to audit the operational calculations and production data for the associated royalty payments; however, such audits may occur many months following our recognition of the royalty revenue and may require us to adjust our royalty revenue in later periods.

If the current global financial conditions and challenging credit markets are prolonged, it may affect the ability of the operators of the properties on which we have royalties to meet liquidity needs or operate profitably, which in turn could have material adverse effects on the value of and revenue from our royalty interests. In addition, current global financial conditions may adversely affect our ability to obtain financing for additional royalty acquisitions.

Current global financial conditions have been subject to increased volatility and uncertainty. The development and operation of mines is very capital intensive, and if the operators of the properties on which we have royalties do not have, in light of prevailing economic conditions, the financial strength or sufficient credit or other financing capability to cover the costs of developing or operating a mine, the operator may curtail, delay or cease development of or operations at a mine site. Many of our principal royalty interests are on development stage properties that require very significant capital to bring the properties into production and our revenues would be materially adversely affected if operators are unable to continue developing or operating a mine in accordance with their expectations due to insufficient financing or if any of the operators enter into bankruptcy or liquidation, or undergo

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a change of control. If any of the operators of the properties on which we have royalties suffer these material adverse effects, then our royalty interests and the value of and revenue from our royalty interests may be materially adversely affected. In addition, if we are unable to obtain debt or equity financing, our ability to acquire additional assets would be adversely affected.

We received significant revenue from royalties on five properties and adverse developments at those properties, as well as depleting resources, could adversely affect our revenue.

Approximately 64% of our revenues were derived from our royalty interests at Taparko, Cortez, Robinson, Leeville and Mulatos in fiscal years 2010 and 2009. We expect that these royalties will continue to be significant contributors to our revenue in future periods. Adverse developments affecting the operation of those properties, including unusual and unexpected geophysical conditions, previously unknown historic underground workings and other matters adversely affecting mining, milling and processing operations, could have a material adverse effect on our revenue from those properties and our results of operations.

As mines on which we have royalties mature, we can expect overall declines in production over the years unless operators are able to replace reserves that are mined through mine expansion or successful new exploration. There can be no assurance that the operators of Cortez or our other properties will be able to maintain or increase production or replace reserves as they are mined.

Certain of our royalty interests are subject to payment or production caps or rights in favor of the operator or third parties that could reduce the revenues generated from the royalty assets.

Some royalty interests are subject to limitations, such that the royalty will extinguish after threshold production is achieved or royalty payments at stated thresholds are made. For example, two of our four royalties at Taparko will terminate once we have received an aggregate of $35 million in revenue from TB-GSR1. We expect that the $35 million payment threshold could be achieved during the first quarter of fiscal year 2011. When the threshold amount is paid, TB-GSR1 and TB-GSR2 will expire and be replaced by TB-GSR3, an ongoing 2% GSR, which will significantly reduce our Taparko revenue. We also expect that the payment cap on our royalty at Siguiri could be reached in the second quarter of fiscal year 2011, at which time we will no longer receive any royalty from Siguiri. Furthermore, other of our royalty agreements contain rights that favor the operator or third parties. Osisko, the operator of Canadian Malartic, one of our principal development properties, has a buy-down right that, if exercised, would reduce our royalty interest. Also, certain individuals from whom we purchased portions of our royalty interest at Pascua-Lama, another of our principal development properties, are entitled to one-time payments if the price of gold exceeds certain thresholds. If any of these thresholds are met or rights are exercised, our future royalty revenue could be reduced.

We may enter into acquisitions or other material royalty transactions at any time.

We are engaged in a continual review of opportunities to acquire existing royalties, to create new royalty assets or similar interests through the financing of mining projects or to acquire companies that hold royalties. We currently, and generally at any time, have acquisition opportunities in various stages of active review, including, for example, our engagement of consultants and advisors to analyze particular opportunities, technical, financial and other confidential information, submission of indications of interest, obtaining or providing debt commitments for acquisition financing, participation in discussions regarding serving as a financing source in connection with royalty acquisitions, and involvement as a bidder in competitive auctions. Any such acquisition could be material to us and could significantly increase the size and scope of our business. In such event, we could issue substantial amounts of common stock or incur substantial additional indebtedness to fund the acquisition.

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Issuances of common stock would dilute the ownership of our existing stockholders and could reduce some or all of our financial measures on a per share basis.

In addition, we may consider opportunities to restructure our royalties where we believe such restructuring would provide a long-term benefit to the Company, though such restructuring may reduce near-term revenues. We could enter into one or more acquisition or restructuring transactions at any time.

We have incurred indebtedness in connection with our royalty acquisitions and could incur substantial additional indebtedness that could have adverse effects on our business.

During the fiscal year 2010, the Company borrowed $255 million under its existing credit facilities. As a result of this indebtedness, we are required to use a portion of our cash flow to service the principal and interest on our debt. This limits the cash flow available to fund acquisitions and dividends and other general corporate purposes. In addition, we may incur substantial additional indebtedness in connection with financing acquisitions, strategic transactions or for other purposes. If we were to incur substantial additional indebtedness, it may become difficult for us to satisfy our debt obligations, increase our vulnerability to general adverse economic and industry conditions or require us to dedicate a substantial portion of our cash flow from operations and proceeds of any equity issuances to payments on our indebtedness, any of which results may place us at a competitive disadvantage to our competitors that have less debt or have other adverse effects upon us.

We may be unable to successfully acquire additional royalty and other similar interests.

Our future success largely depends upon our ability to acquire royalty interests at appropriate valuations, including through corporate acquisitions, to replace depleting reserves and to diversify our royalty portfolio. We anticipate that most of our revenues will be derived from royalty and other similar interests that we acquire or finance, rather than through exploration of properties. There can be no assurance that we will be able to identify and complete the acquisition of such royalty interests, or businesses that own desired royalty interests, at reasonable prices or on favorable terms. In addition, we face competition in the acquisition of royalty and other similar interests. If we are unable to successfully acquire additional royalties or other similar interests, the reserves subject to our royalties will decline as the producing properties on which we have royalties are mined or payment or production caps on certain of our royalties are met. We may also experience negative reactions from the financial markets or operators of properties on which we seek royalties and other similar interests if we are unable to successfully complete acquisitions of royalty interests or businesses that own desired royalty interests. Each of these factors may adversely affect the trading price of our common stock or our financial condition or results of operations.

On July 15, 2010, we entered into a letter agreement pursuant to which we agreed to acquire 25% of the payable gold produced from the Mt. Milligan copper-gold project in British Columbia from Thompson Creek Metals Company Inc. or its affiliate ("Thompson Creek") concurrent with the closing of Thompson Creek's proposed acquisition of Terrane Metals Corp. ("Terrane"). There can be no assurance that Thompson Creek's proposed acquisition of Terrane will be successful, and therefore, there can be no assurance that we will be successful in acquiring 25% of the payable gold produced from the Mt. Milligan project.

Estimates of production by the operators of mines in which we have royalty interests are subject to change, and actual production may vary materially from such estimates.

Production estimates are prepared by the operators of mining properties. There are numerous uncertainties inherent in estimating anticipated production attributable to our royalty interests, including many factors beyond our control and the control of the operators of properties in which we

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have royalty interests. We do not participate in the preparation or verification of production estimates and have not independently assessed or verified the accuracy of such information. The estimation of anticipated production is a subjective process and the accuracy of any such estimates is a function of the quality of available data, reliability of production history, variability in grade encountered, mechanical or other problems encountered, engineering and geological interpretation and operator judgment. Rates of production may be less than expected. Results of drilling, metallurgical testing and production, changes in commodity prices, and the evaluation of mine plans subsequent to the date of any estimate may cause actual production to vary materially from such estimates.

Estimates of reserves and mineralization by the operators of mines in which we have royalty interests are subject to significant revision.

There are numerous uncertainties inherent in estimating proven and probable reserves and mineralization, including many factors beyond our control and the control of the operators of mineral properties on which we have royalty interests. Reserve estimates on our royalty interests are prepared by the operators of the mining properties. We do not participate in the preparation or verification of such reports and have not independently assessed or verified the accuracy of such information. The estimation of reserves and of other mineralized material is a subjective process, and the accuracy of any such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, metallurgical testing and production, and the evaluation of mine plans subsequent to the date of any estimate, may cause a revision of such estimates. The volume and grade of reserves recovered and rates of production may be less than anticipated. Assumptions about gold and other precious metal prices are subject to great uncertainty, and such prices have fluctuated widely in the past. Declines in the market price of gold or other precious metals also may render reserves or mineralized material containing relatively lower grades of ore uneconomical to exploit. Changes in operating costs and other factors including geotechnical characteristics and metallurgical recovery, may materially and adversely affect reserves. Finally, it is important to note that our royalties give us interests in only a portion of the production from the operators' aggregate reserves, and those interests vary widely based on the individual royalty documents.

Our disclosure controls and internal control over our financial reporting are subject to inherent limitations.

Management has concluded that as of the period ended June 30, 2010, our disclosure controls and procedures and our internal control over financial reporting were effective. Such controls and procedures, however, may not be adequate to prevent or identify existing or future internal control weaknesses due to inherent limitations that are beyond our control, including, but not limited to, our dependence on operators for the calculations of royalty payments as discussed in the above risk factor. There is a risk that material misstatements in results of operations and financial condition may not be prevented or detected on a timely basis by our internal controls over financial reporting and may require us to restate our financial statements, as we did in fiscal year 2008. This could, in turn, adversely affect the trading price of our common stock and there is a risk that repeated restatements could result in an investigation by the SEC.

Royalty interests are subject to title and other defects and contest by operators of mining projects and holders of mining rights, and these risks may be hard to identify in acquisition transactions.

We sometimes acquire portfolios of royalty interests. For example, we acquired 80 royalty interests when we acquired IRC. While Royal Gold seeks to confirm the existence, validity, enforceability and geographic extent of the royalties it acquires, there can be no assurance that disputes over these and other matters will not arise. Royalty interests in mining projects or properties generally are subject to uncertainties and complexities arising from the application of contract and property laws governing

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private parties and/or local or national governments in the jurisdiction where mining projects are located. For example, the validity of unpatented mining claims, which constitute a significant portion of the properties on which we hold royalties in the United States, is often uncertain and such validity is always subject to contest. Unpatented mining claims are generally considered subject to greater title risk than patented mining claims, or real property interests that are held by absolute title to the land (known legally as "fee simple" ownership). Furthermore, royalties in many jurisdictions are contractual in nature, rather than interests in land, and therefore are subject to change of control, bankruptcy or insolvency of operators, and to challenges of various kinds brought by operators or third parties. We do not usually have the protection of security interests over property that we could liquidate to recover all or some part of our investment in the royalty. Disputes could also arise challenging, among other things, the existence or geographic extent of the royalty, third party claims to the same royalty asset or to the property on which we have a royalty, various rights of the operator or third parties in or to the royalty, methods for calculating the royalty, production and other thresholds and caps applicable to royalty payments, the obligation of an operator to make royalty payments, and various defects in the royalty agreement itself. Unknown defects in the royalties we acquire may prevent us from realizing the anticipated benefits from the acquisition, and could materially adversely affect our revenue and results of operations.

Changes in federal and state legislation could decrease our royalty revenues.

A number of the properties on which we have royalties are located on U.S. federal lands that are subject to federal mining and other public land laws. Changes in federal or state laws or the regulations promulgated under them could affect mine development and expansion, significantly increase regulatory obligations and compliance costs with respect to mine development and mine operations, increase the cost of holding mining claims or impose additional taxes on mining operations, all of which could adversely affect our royalty revenue from such properties. In recent years, the United States Congress has considered a number of proposed major revisions to the General Mining Law of 1872 (the "General Mining Law"), which governs the creation, maintenance and possession of mining claims and related activities on federal public lands in the United States. Four such proposals are currently pending. Bills H.R. 699 and S. 140 were introduced in the Congress in January 2009 and S. 796 and H.R. 3201 were introduced in April and July, 2009, respectively. Provisions in these proposed bills, if enacted, would impose royalties payable to the government on production, increase land holding fees, impose federal reclamation fees, impose additional environmental operating standards and afford greater public involvement and regulatory discretion in the mine permitting process. If enacted, legislation such as H.R. 699, S. 140, S. 796 and H.R. 3201 could adversely affect the development of new mines and the expansion of existing mines, as well as increase the cost of all mining operations on federal lands, perhaps materially and adversely affecting mine operators and, therefore, our royalty revenue. By way of example, if a royalty, assessment, production tax, or other levy imposed on and measured by production is charged to the operator at Cortez, which is largely located on U.S. federal lands, the amount of that charge would be deducted from gross proceeds for calculation of our GSR1, GSR2 and GSR3 royalties, which would reduce our royalty revenues from these royalty interests.

Foreign operations and operation by foreign operators are subject to many risks.

We derived approximately 60% of our revenues from foreign sources during fiscal 2010, compared to 44% in fiscal 2009. Our principal producing royalties on properties outside of the United States are located in Australia, Burkina Faso, Canada, Mexico and Spain. We currently have interests in mines and projects outside of the United States in Argentina, Australia, Bolivia, Brazil, Burkina Faso, Canada, Chile, Colombia, Dominican Republic, Finland, Ghana, Guatemala, Honduras, Mexico, Nicaragua, Peru, the Republic of Guinea, Russia, Spain and Tunisia. Our foreign activities are subject to the risks normally associated with conducting business in foreign countries. These risks include, depending on the country, such things as volatile exchange controls and currency fluctuations, inflation, limitations on

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repatriation of earnings, foreign taxation, enforcement of unfamiliar or uncertain foreign real estate, contract and environmental laws, expropriation or nationalization of property, labor practices and disputes, changes in legislation that could substantially increase the cost of mining operations, war, civil unrest and uncertain political and economic environments. Recently proposed tax legislation in Australia, Chile and other foreign jurisdictions could impose large tax obligations on operators that could materially adversely affect the feasibility of new mine development and the profitability of existing mining operations. In addition, many of our operators are organized outside of the United States. Our royalty interests may be subject to the application of foreign laws to our operators, and their stockholders, including laws relating to foreign ownership structures, corporate transactions, creditors' rights, bankruptcy and liquidation. Foreign operations also could be adversely impacted by laws and policies of the United States affecting foreign trade, investment and taxation.

The mining industry is subject to significant environmental risks.

Mining is subject to potential risks and liabilities associated with pollution of the environment and the disposal of waste products occurring as a result of mineral exploration and production. Laws and regulations in the United States and abroad intended to ensure the protection of the environment are constantly changing and generally are becoming more restrictive and costly. Furthermore, mining may be subject to significant environmental and other permitting requirements regarding the use of raw materials, particularly water, needed for operations. If an operator is forced to incur significant costs to comply with environmental regulations or becomes subject to environmental restrictions that limit its ability to continue or expand operations, or if an operator were to lose its right to use or access water or other raw materials necessary to operate a mine, our royalty revenues could be reduced, delayed, or eliminated. These risks are most salient with regard to our development stage royalty properties where permitting may not be complete and where new legislation and regulation can lead to delays, interruptions and significant unexpected cost burdens for mine operators. For example, legislation is pending in Argentina which, if enacted, could stop or curtail mining activities on or near the country's glaciers. We have royalty interests on the Chilean side of the Pascua-Lama Project, which straddles the border between Chile and Argentina, and the new legislation in Argentina, if passed, could affect the feasibility, design, development and operation of the Pascua-Lama Project. Further, to the extent that we become subject to environmental liabilities for the time period during which we were operating properties, the satisfaction of any liabilities would reduce funds otherwise available to us and could have a material adverse effect on our financial condition, results of operations and cash flows.

Regulations and pending legislation governing issues involving climate change could result in increased operating costs to the operators of the properties on which we have royalties.

A number of governments or governmental bodies have introduced or are contemplating regulatory changes in response to the potential impacts of climate change. The December 1997 Kyoto Protocol, which ends in 2012, established a set of greenhouse gas emission targets for countries that have ratified the Protocol, which include Canada, Ghana, Australia and Peru. Furthermore, the U.S. Congress and several states have initiated legislation regarding climate change that will affect energy prices and demand for carbon intensive products. Additionally, the Australian Government may potentially reintroduce a national emissions trading scheme and mandatory renewable energy targets. Legislation and increased regulation regarding climate change could impose significant costs on the operators of the properties on which we have royalties, including increased energy, capital equipment, environmental monitoring and reporting and other costs to comply with such regulations. If an operator of a property on which we have royalty interests is forced to incur significant costs to comply with climate change regulation or becomes subject to environmental restrictions that limit its ability to continue or expand operations, our royalty revenues from that property could be reduced, delayed, or eliminated.

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We depend on the services of our President and Chief Executive Officer and other key employees and on the participation of our Chairman.

We believe that our success depends on the continued service of our key executive management personnel. Currently, Tony Jensen is serving as our President and Chief Executive Officer. Mr. Jensen's extensive commercial experience, mine operations background and industry contacts give us an important competitive advantage. Furthermore, our Chairman, Stanley Dempsey, who served as our Executive Chairman until his retirement in January 2009, remains closely involved with us. Mr. Dempsey's knowledge of the royalty business and long-standing relationship with the mining industry are important to our success. The loss of the services of Mr. Jensen or other key employees could jeopardize our ability to maintain our competitive position in the industry. We currently do not have key person life insurance for any of our officers or directors.

Risks Related to Our Common Stock

Our stock price may continue to be volatile and could decline.

The market price of our common stock has fluctuated and may decline in the future. The high and low sale prices of our common stock on the NASDAQ Global Select Market were $35.42 and $23.85 for the fiscal year ended June 30, 2008, $49.81 and $22.75 for the fiscal year ended June 30, 2009 and $55.96 and $37.35 for the fiscal year ended June 30, 2010. The fluctuation of the market price of our common stock has been affected by many factors that are beyond our control, including:

- market prices of gold and other metals;
- interest rates;
- expectations regarding inflation;
- ability of operators to produce precious metals and develop new reserves;
- currency values;
- credit market conditions;
- general stock market conditions; and
- global and regional political and economic conditions.

Additional issuances of equity securities by us would dilute the ownership of our existing stockholders and could reduce some or all of our financial measures on a per share basis, reduce the trading price of our common stock or impede our ability to raise future capital.

We may issue equity in the future in connection with acquisitions, strategic transactions or for other purposes. To the extent we issue additional equity securities, the ownership of our existing stockholders would be diluted and some or all of our financial measures on a per share basis could be reduced. In addition, the shares of common stock that we issue in connection with an acquisition may not be subject to resale restrictions. The market price of our common stock could decline if certain large holders of our common stock, or recipients of our common stock in connection with an acquisition, sell all or a significant portion of their shares of common stock or are perceived by the market as intending to sell these shares other than in an orderly manner. In addition, these sales could also impair our ability to raise capital through the sale of additional common stock in the capital markets.

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We may change our practice of paying dividends.

We have paid a cash dividend on our common stock for each fiscal year beginning in fiscal year 2000. Our board of directors has discretion in determining whether to declare a dividend based on a number of factors, including prevailing gold prices, economic market conditions and funding requirements for future opportunities or operations. If our board of directors declines to declare dividends in the future or reduces the current dividend level, then our stock price could fall, and the success of an investment in our common stock would depend solely upon any future stock price appreciation. We have increased our dividends in prior years. There can be no assurance, however, that we will continue to do so. For example, if we were to materially increase our borrowings to conduct a material acquisition, our board of directors could elect to modify our practice of paying dividends and potentially reduce or eliminate dividends on common stock.

Certain anti-takeover provisions could delay or prevent a third party from acquiring us.

Provisions in our restated certificate of incorporation may make it more difficult for third parties to acquire control of us or to remove our management. Some of these provisions:

- permit our board of directors to issue preferred stock that has rights senior to the common stock without stockholder approval;
- provide for three classes of directors serving staggered, three-year terms; and
- require certain advanced notice of information relating to stockholder nominations and proposals.

We are also subject to the business combination provisions of Delaware law that could delay, deter or prevent a change in control. In addition, we have adopted a stockholder's rights plan that imposes significant penalties upon a person or group that acquires 15% or more of our outstanding common stock without the approval of the board of directors. Any of these measures could prevent a third party from pursuing an acquisition of Royal Gold, even if stockholders believe the acquisition is in their best interests.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We do not own or operate the properties in which we have royalty interests and therefore much of the information disclosed in this Form 10-K regarding these properties is provided to us by the operators. For example, the operators of the various properties provide us information regarding metals production, estimates of mineral reserves and additional mineralized material. Reserves are summarized below in this report in Item 2, Properties, Reserve Information. Our rights to information from the operators under our royalty agreements vary by royalty and by operator and we may not be entitled to information regarding certain properties. We do not participate in the preparation or calculation of the operators' estimates, production reports or reserve calculations and have not independently assessed or verified the accuracy of such information.

There is more information available to the public regarding certain properties in which we have royalties, including reports filed with the SEC or with the Canadian securities regulatory agencies available at www.sec.gov or www.sedar.com, respectively. For risks to our business associated with operations of mining properties by third parties see generally the risks described under Part I, Item 1A, Risk Factors. For risks associated with the operators' reserve estimates, please see Part I, Item 1A, Risk

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Factors, *Estimates of reserves and mineralization by the operators of mines in which we have royalty interests are subject to significant revision*, of this report for further detail.

The description of our principal royalties set forth in this Item 2, Properties, includes the location, operator, reserves and our royalty rate and interests. The descriptions do not include material current developments at each property. Material current developments announced by the operators are discussed in Item 7, MD&A, of this report.

Principal Royalties on Producing Properties

Recent activities and further information for each of the principal producing properties in which we have a royalty interest are described in the following pages. The Company considers both historical and future potential revenues in determining which royalties in our portfolio are principal to our business. Estimated future potential royalty revenues from both producing and development properties are based on a number of factors, including reserves subject to our royalty interests, production estimates, feasibility studies, metal price assumptions, mine life, legal status and other factors and assumptions, any of which could change and could cause Royal Gold to conclude that one or more of such royalties are no longer principal to our business. Reserves for all of our producing properties are summarized in this report in Item 2, Properties, Reserve Information. As of June 30, 2010, the Company considers the properties discussed below principal to our business.

Andacollo (Region IV, Chile)

We own a royalty on all gold produced from the sulfide portion of the Andacollo copper and gold deposit. The Andacollo Royalty equals 75% of the gold produced from the sulfide portion of the deposit at the Andacollo mine until 910,000 payable ounces of gold have been sold, and 50% of the gold produced in excess of 910,000 payable ounces of gold.

Andacollo is an open-pit copper mine located in central Chile, Region IV in the Coquimbo Province and is operated by a subsidiary of Teck Resources Limited ("Teck"). Andacollo is located in the foothills of the Andes Mountains approximately 1.5 miles southwest of the town of Andacollo. The provincial capital of La Serena and the coastal city of Coquimbo are approximately 34 miles northeast of the Andacollo project by road and Santiago is approximately 215 miles south by air. Access to the mine is provided by taking Route 43 (R-43) south from La Serena to El Peñon. From El Peñon, D-51 is followed east and eventually curving to the south to Andacollo. Both R-43 and D-51 are paved roads.

As of December 31, 2009, Teck estimated that at a $500 per ounce gold price, proven and probable reserves were 437.2 million tons, at an average grade of 0.004 ounces per ton containing 1.631 million ounces of gold.

Please refer to Item 7, MD&A, of this report for further discussion on the Andacollo Royalty.

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The following aerial photo depicts the area subject to our royalty interest at Andacollo:

Voisey's Bay (Labrador, Canada)

As a result of the IRC Transaction, we own an effective 2.7% NSR royalty on the Voisey's Bay nickel-copper-cobalt mine located in Newfoundland and Labrador, Canada and operated by Vale. The Company owns 90% of a 3.0% NSR (or 2.7%) while a non-controlling interest owns the remainder. The Voisey's Bay project is located on the northeast coast of Labrador, on a peninsula bordered to the north by Anaktalak Bay and to the south by Voisey's Bay. The nearest communities are Nain, approximately 20 miles northeast, and Natuashish, approximately 50 miles southeast. The property is 205 miles north of Happy Valley-Goose Bay, in south-central Labrador, and 560 miles north-northwest of St. John's, the capital of the Province. Access to the property is by helicopter, small aircraft or tracked vehicles during the winter.

As of December 31, 2009, Vale reported that nickel, copper and cobalt reserves were 27.6 million tons, at an average grade of 2.71% nickel, 1.58% copper and 0.13% cobalt containing 1,493 million pounds of nickel, 873 million pounds of copper and 74 million pounds of cobalt. Reserves were calculated at $11.01 or less per pound of nickel, $2.91 or less per pound of copper, and $22.70 or less per pound of cobalt.

Please refer to Item 7, MD&A, of this report for a further discussion on the IRC Transaction.

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The following aerial photo depicts the area subject to our royalty interest at Voisey's Bay:

Cortez (Nevada, USA)

Cortez is a large open pit, mill and heap leach operation located approximately 60 air miles southwest of Elko, Nevada, in Lander County. The site is reached by driving west from Elko on Interstate 80 approximately 46 miles, and proceeding south on State Highway 306 approximately 23 miles. Cortez includes the Pipeline, South Pipeline, Gap and Crossroads deposits and is operated by subsidiaries of Barrick.

The royalty interests we hold at Cortez include:

(a) *Reserve Claims ("GSR1").* This is a sliding-scale GSR royalty for all products from an area originally known as the "Reserve Claims," which includes the majority of the Pipeline and South Pipeline deposits. As defined in our royalty agreement with Cortez, our GSR royalty applies to revenues attributed to products mined and removed, with no deduction for any costs paid by or charged to Cortez, except for deductions for refining and transportation of doré and Mining Law reform costs. Mining Law reform costs include all amounts paid by or charged to Cortez for any royalty, assessment, production tax or other levy imposed on and measured by production, to the extent that any such levy is hereafter imposed by the United States in connection with reform of the General Mining Law or otherwise. As defined, no such Mining Law reform costs are currently deducted since no such reform has occurred. The revenues attributed to Cortez are determined on a deemed market value basis of total production for each calendar quarter outturned to Cortez's account at the refiner. The GSR

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royalty rate on the Reserve Claims is tied to the gold price as shown in the table below and does not include indexing for inflation or deflation.

(b)

GAS Claims ("GSR2"). This is a sliding-scale GSR royalty for all products from an area outside of the Reserve Claims, originally known as the "GAS Claims," which encompasses approximately 50% of the GAP deposit and all of the Crossroads deposit. The GSR royalty rate on the GAS Claims, as shown in the table below, is tied to the gold price, without indexing for inflation or deflation, and applies to revenues attributed to products mined and removed, with no deduction of costs, except for refining and transportation of doré and Mining Law reform costs, if any. The GSR2 royalty applies to the mining claims that comprise the Crossroads deposit and approximately 50% of the GAP deposit.

(c)

Reserve and GAS Claims Fixed Royalty ("GSR3"). The GSR3 royalty is a fixed rate GSR royalty of 0.7125% and originally covered the same cumulative area as is covered by our two sliding-scale GSR royalties, GSR1 and GSR2. However, our GSR3interest does not cover the mining claims that comprise the undeveloped Crossroads deposit.

(d)

Net Value Royalty ("NVR1"). This is a fixed 1.25% NVR on production from the GAS Claims located on a portion of Cortez that excludes the Pipeline open pit. The Company owns 31.6% of the 1.25% NVR (or 0.39%) while limited partners (including certain directors of the Company) in the partnership, which is consolidated in our financial statements, own the remaining portion of the 1.25% NVR. This NVR1 royalty is calculated by deducting contract defined processing-related and associated capital costs, but not mining costs, from the revenue received by the operator for production from the area covered by the royalty. Our 0.39% portion of the NVR1 royalty does not cover the mining claims that comprise the undeveloped Crossroads deposit.

We also own three other royalties in the Cortez area where there is currently no production and no reserves attributed to these royalty interests.

The following shows the current sliding-scale GSR1 and GSR2 royalty rates under our royalty agreement with Cortez:

London P.M. Quarterly Average Price of Gold Per Ounce ($U.S.)	**GSR1 and GSR2 Royalty Percentage**
Below $210.00	0.40%
$210.00 - $229.99	0.50%
$230.00 - $249.99	0.75%
$250.00 - $269.99	1.30%
$270.00 - $309.99	2.25%
$310.00 - $329.99	2.60%
$330.00 - $349.99	3.00%
$350.00 - $369.99	3.40%
$370.00 - $389.99	3.75%
$390.00 - $409.99	4.00%
$410.00 - $429.99	4.25%
$430.00 - $449.99	4.50%
$450.00 - $469.99	4.75%
$470.00 - and above	5.00%

Under certain circumstances we would be entitled to delayed production payments (*i.e.*, payments not recoupable by Cortez) of $400,000 per year.

Barrick estimated that at an $825 per ounce gold price, proven and probable reserves related to our royalty interests at Cortez includes 134.2 million tons of ore, at an average grade of 0.039 ounces per ton, containing approximately 5.244 million ounces of gold as of December 31, 2009.

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Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Cortez.

The following aerial photo depicts the area subject to our royalty interests at Cortez:

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Taparko (Burkina Faso, West Africa)

We own a 15.0% GSR royalty (TB-GSR1) and a sliding-scale GSR royalty (TB-GSR2), ranging from 0% to 10.0% depending on the price of gold, on all gold produced from the Taparko open pit gold mine. The Taparko mine is located in Burkina Faso, West Africa, and is operated by Somita, a subsidiary of High River. The Taparko mine is accessible by paved roads and is approximately 125 miles northeast of Ouagadougou, the capital of Burkina Faso.

TB-GSR1 will remain in effect until cumulative production of 804,420 ounces of gold is achieved or until cumulative payments of $35 million have been made to Royal Gold, whichever is earlier. TB-GSR2 will remain in effect until the termination of TB-GSR1. Production at the Taparko mine commenced during our first fiscal quarter of 2008. As of June 30, 2010, we have recognized royalty revenue associated with the TB-GSR1 royalty totaling $30.6 million, which is attributable to cumulative production of approximately 202,000 ounces of gold. Management estimates that, based on Taparko's last three quarters of production and its calendar 2010 production guidance, the $35 million cap associated with TB-GSR1 could be met during the third calendar quarter of 2010.

We also own a perpetual 2.0% GSR royalty (TB-GSR3) on all gold produced from the Taparko mine that applies to production following the termination of TB-GSR1 and TB-GSR2 royalties. A portion of the TB-GSR3 royalty is associated with existing proven and probable reserves and has been classified as a development stage royalty interest. The remaining portion of the TB-GSR3 royalty, which is not currently associated with proven and probable reserves, is classified as an exploration stage royalty interest.

In addition, we own a 0.75% milling fee royalty (TB-MR1) on all gold processed through the Taparko mine processing facilities that is mined from any area outside of the Taparko mine area, subject to a maximum of 1.1 million tons per year. There currently are no proven and probable reserves associated with TB-MR1, and this royalty is classified as an exploration stage royalty interest.

As of December 31, 2009, High River estimated that at an $800 per ounce gold price, proven and probable reserves include 8.0 million tons of ore, at an average grade of 0.085 ounces per ton, containing 0.683 million ounces of gold. Management estimates that as of December 31, 2009, 0.132 million contained ounces will be depleted to reach the $35 million cap on TB-GSR1 royalty. Upon meeting the $35 million cap, the remaining 0.551 million contained ounces of estimated gold will be associated with the TB-GSR3 royalty once it becomes effective.

Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Taparko.

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The following aerial photo depicts the area subject to our royalty interests at the Taparko mine:

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Robinson Mine (Nevada, USA)

We own a 3.0% NSR royalty on all mineral production from the Robinson open pit mine operated by a subsidiary of Quadra. The Robinson mine produces two flotation concentrates for sale to third party smelters. One concentrate contains copper, gold and silver. The second is a molybdenum concentrate. Access to the property is via Nevada State Highway 50, 6.5 miles west of Ely, Nevada, in White Pine County.

As of December 31, 2009, Quadra informed us that the copper and gold reserves were 113.6 million tons, at an average grade of 0.006 ounces per ton of gold, containing 0.704 million ounces of gold and a copper grade of 0.53% containing 1,203 million pounds of copper. The reserves were calculated at $2.00 per pound of copper and $800 per ounce of gold. Silver and molybdenum reserves were not reported but are produced and sold as by-products.

Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Robinson.

The following aerial photo depicts the area subject to our royalty interest at the Robinson mine:

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Leeville (Nevada, USA)

We own a carried working interest, equal to a 1.8% NSR royalty, which covers the majority of the Leeville property, in Eureka County, Nevada. The Leeville Mining Complex is approximately 19 air miles northwest of Carlin, Nevada, and is operated by a subsidiary of Newmont. The property is accessed by driving north from Carlin on Nevada State Highway 766 for 19 miles and then on an improved gravel road for two miles.

At Leeville, proven and probable reserves, at an $800 per ounce gold price, include 5.3 million tons of ore, at an average grade of 0.338 ounces per ton, containing 1.790 million ounces of gold as of December 31, 2009.

The following aerial photo depicts the area subject to our royalty interest at Leeville:

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Mulatos (Sonora, Mexico)

We own a 1.0% to 5.0% sliding-scale NSR royalty on the Mulatos open pit mine in southeastern Sonora, Mexico. The Mulatos mine is located approximately 137 miles east of the city of Hermosillo and 186 miles south of the border with the United States and is operated by Alamos. Access to the mine from the city of Hermosillo can be made via private chartered flight or paved and gravel road.

The Mulatos royalty is capped at 2.0 million gold ounces of production. As of June 30, 2010, approximately 581,000 cumulative ounces of gold have been produced.

As of December 31, 2009, based upon a gold price of $800 per ounce, Alamos has reported proven and probable reserves of 67.9 million tons, at an average grade of 0.035 ounces per ton, containing 2.387 million ounces of gold.

Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Mulatos.

The following aerial photo depicts the area subject to our royalty interest at the Mulatos mine:

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Peñasquito (Zacatecas, Mexico)

We own a production payment equivalent to a 2.0% NSR royalty on all metal production from the Peñasquito project, located in the State of Zacatecas, Mexico, and operated by Goldcorp. The Peñasquito project is located approximately 17 miles west of the town of Concepción del Oro, Zacatecas, Mexico. The project, composed of two main deposits called Peñasco and Chile Colorado, hosts large silver, gold, zinc and lead reserves. The deposits contain both oxide and sulfide material. Access to the site is via either paved or cobbled roads west out of Concepcion del Oro nine miles to the town of Mazapil and then further approximately seven miles west from Mazapil.

Goldcorp estimates that at a gold price of $825 per ounce and a silver price of $13 per ounce, proven and probable oxide reserves as of December 31, 2009 total 79.9 million tons of ore, at an average gold grade of 0.005 ounces per ton, containing 0.400 million ounces of gold, and at an average silver grade of 0.43 ounces per ton containing 34.5 million ounces of silver. Estimates for the sulfide reserves use the same gold and silver prices as the oxide reserve and include lead and zinc reserve estimates at a reserve price of $0.60 per pound for lead and $0.80 per pound for zinc. Proven and probable sulfide reserves as of December 31, 2009 include 1,261.9 million tons of ore, at an average gold grade of 0.014 ounces per ton, a silver grade of 0.82 ounces per ton, a lead grade of 0.29% and a zinc grade of 0.63% yielding contained metal of 17.420 million ounces of gold, 1,035.6 million ounces of silver, 7,211 million pounds of lead and 15,930 million pounds of zinc.

Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Peñasquito.

The following aerial photo depicts the area subject to our royalty interest at Peñasquito:

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Dolores (Chihuahua, Mexico)

We own a 1.25% NSR royalty on gold and a 2.0% NSR royalty on both gold and silver from the Dolores project located in Chihuahua, Mexico, and operated by Minefinders. The Dolores project is located approximately 155 miles west of the city of Chihuahua, Mexico. The property can be accessed by approximately 56 miles of recently upgraded access road from Yepachi, Chihuahua, to the mine site. Access to the property can also be achieved by light aircraft landing on a dirt strip located about five miles from the mine site.

As of December 31, 2008, based upon a gold and silver price of $600 and $10 per ounce, respectively, Minefinders reported proven and probable gold reserves of 109.5 million tons, at an average gold grade of 0.022 ounces per ton, and an average silver grade of 1.16 ounces per ton, containing 2.444 million ounces of gold and 126.6 million ounces of silver. The Company did not receive updated reserve information as of December 31, 2009 from the operator.

Please refer to Item 7, MD&A, of this report for further discussion of recent developments at Dolores.

The following map depicts the area subject to our royalty interests at Dolores:

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Las Cruces (Andalucía, Spain)

As a result of the IRC Transaction, we own a 1.5% NSR royalty on the Las Cruces copper project located in Andalucía, Spain and operated by Inmet. The Las Cruces mine is located in the Sevilla Province of southern Spain, about 12 miles northwest of the Province capital city of Seville. Access to the site is by well-maintained paved roads.

As of December 31, 2009, Inmet reported copper reserves of 18.2 million tons, at an average grade of 6.3% copper, containing 2,304 million pounds of copper. Reserves were calculated at $2.00 per pound of copper.

Please refer to Item 7, MD&A, of this report for a further discussion of the IRC Transaction.

The following aerial photo depicts the area subject to our royalty interest at Las Cruces:

Gwalia Deeps (Western Australia, Australia)

As a result of the IRC Transaction, we own a 1.5% NSR royalty on gold produced from the Gwalia Deeps mine located near the town of Leonora, Western Australia and operated by St. Barbara. The Gwalia Deeps mine in an underground mine within St. Barbara's Leonora operations. The mine can be accessed by taking the Goldfields Highway north out of Kalgoorlie for approximately 245 miles to the town of Leonora.

As of June 30, 2009, St. Barbara Limited reported gold reserves of 8.7 million tons, at an average grade of 0.227 ounces per ton, containing 1.980 million ounces of gold. Reserves were calculated at

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A$1,250 (Australian dollars) for the operator's fiscal 2010 and at A$850 (Australian dollars) per ounce of gold thereafter.

Please refer to Item 7, MD&A, of this report for a further discussion on the IRC Transaction.

The following aerial photo depicts the area subject to our royalty interest at Gwalia Deeps:

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Principal Royalties on Development Stage Properties

The following is a description of our principal royalty interests on development stage properties. There are proven and probable reserves associated with these properties as indicated below. These development stage royalty interests are not currently in production. Reserves for all of our development stage properties are summarized below in this report in Item 2, Properties Reserve Information.

Pascua-Lama Project (Region III, Chile)

As of June 30, 2010, we own a 0.67% to 4.48% sliding-scale NSR royalty on the Pascua-Lama project located on both sides of the border between Argentina and Chile, and operated by Barrick. Our royalty interest is applicable to all gold production from the portion of the Pascua-Lama project lying on the Chilean side of the border. As discussed in further detail in Item 7, MD&A, under "Recent Developments, Business Developments," on July 1, 2010, the Company entered into two separate assignment of rights agreements with two private Chilean citizens whereby Royal Gold acquired (i) a 0.35% sliding-scale NSR royalty and (ii) the right to acquire an additional 0.40% sliding-scale NSR royalty on the Pascua-Lama project. Upon the closing of the 0.40% sliding-scale NSR royalty acquisition, which is expected to occur during the second quarter of fiscal 2011, the Company's sliding-scale NSR on the Pascua-Lama project will be 0.78% to 5.23%. The Company has certain contingent rights and obligation with respect to the portion of the Pascua-Lama royalty acquired in the IRC Transaction. Please refer to Item 7, MD&A, under "Recent Developments, Business Developments" for further discussion on the contingent rights and obligations.

The Pascua-Lama project is located within 7 miles of Barrick's operating Veladero mine. Access to the project is from the city of Vallenar, Region III, Chile, via secondary roads C-485 to Alto del Carmen, Chile, and C-489 from Alto del Carmen to El Corral, Chile.

As of June 30, 2010, the sliding-scale NSR royalty is based upon the gold prices as shown in the following table.

London Bullion Market Association P.M. Monthly Average Price of Gold per Ounce (US$)	NSR Royalty Percentage
less than $325	0.67%
$400	1.34%
$500	2.33%
$600	3.05%
$700	3.76%
$800 or greater	4.48%

Note: Royalty rate is interpolated between the upper and lower endpoints.

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Upon completion of the acquisition of the additional royalty interest, the sliding-scale NSR royalty is based upon the gold prices as shown in the following table:

London Bullion Market Association P.M. Monthly Average Price of Gold per Ounce (US$)	**ADDING-BOTTOM: 4px">**

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 for Unit History, Accumulated Other Comprehensive
Income (Loss) and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2011	$12,464.8	$ (351.4)	$ 105.9	$12,219.3
Net income	651.3	--	4.2	655.5
Cash distributions paid to limited partners	(530.4)	--	--	(530.4)
Cash distributions paid to noncontrolling interests	--	--	(6.6)	(6.6)
Cash contributions from noncontrolling interests	--	--	4.9	4.9
Net cash proceeds from issuance of common units	29.0	--	--	29.0
Amortization of fair value of equity-based awards	15.6	--	--	15.6
Cash flow hedges	--	(6.0)	--	(6.0)
Change in fair value of available-for-sale equity securities	--	15.8	--	15.8
Other	(9.7)	(0.2)	1.1	(8.8)
Balance, March 31, 2012	$12,620.6	$ (341.8)	$ 109.5	$12,388.3

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2010	$11,406.7	$ (32.5)	$ 526.6	$11,900.8
Net income	420.7	--	13.8	434.5
Cash distributions paid to limited partners	(479.7)	--	--	(479.7)
Cash distributions paid to noncontrolling interests	--	--	(17.2)	(17.2)
Cash contributions from noncontrolling interests	--	--	1.3	1.3
Net cash proceeds from issuance of common units	21.0	--	--	21.0
Amortization of fair value of equity-based awards	12.0	--	0.1	12.1
Cash flow hedges	--	(66.9)	--	(66.9)
Other	(3.7)	(0.7)	(1.5)	(5.9)
Balance, March 31, 2011	$11,377.0	$ (100.1)	$ 523.1	$11,800.0

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

With the exception of per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

KEY REFERENCES USED IN THESE
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to “we,” “us,” “our,” “Enterprise” or “Enterprise Products Partners” a intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC (“Enterprise GP”), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees (“DD LLC Trustees”) of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees (“EPCO Trustees”) of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer (“CEO”) of EPCO. Each of the EPCO Trustees is also a director of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC (“Duncan MergerCo,” a Delaware limited liability company and our wholly owned subsidiary), Duncan Energy Partners L.P. (“Duncan Energy Partners”) and DEP Holdings, LLC (“DEP GP,” the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the “Duncan Merger Agreement”). On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the “Duncan Merger”). See Note 1 for additional information regarding the Duncan Merger.

References to “TEPPCO” mean TEPPCO Partners, L.P. prior to its merger with one of our subsidiaries on October 26, 2009.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries.

Note 1. Partnership Operations, Organization and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

include approximately 50,600 miles of onshore and offshore pipelines; 190 million barrels ("MMBbls") of storage capacity for NGLs, crude oil, refined products and certain petrochemicals; and 14 billion cubic feet ("Bcf") of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments.

We are 100% owned by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 12 for information regarding the ASA and other related party matters.

Completion of Duncan Merger

On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo and Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary. Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. Enterprise issued 24,277,310 of its common units (net of fractional common units cashed out) as consideration in the Duncan Merger. No Enterprise common units were issued to Enterprise or its subsidiaries as merger consideration. Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements.

Note 2. General Accounting Matters

Our results of operations for the three months ended March 31, 2012 are not necessarily indicative of results expected for the full year of 2012. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC").

These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2011 (the "2011 Form 10-K") filed with the SEC on February 29, 2012.

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. The following table presents our allowance for doubtful accounts activity for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Balance at beginning of period	$13.4	$18.4
Charged to costs and expenses	0.1	0.2
Deductions (1)	(0.5)	(5.1)
Balance at end of period	$13.0	$13.5

(1) The 2011 deduction is primarily due to our reassessment of the allowance for doubtful accounts as a result of improved credit ratings of a significant customer, which reduced our exposure to potential uncollectibility.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 14 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as futures, swaps, options, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates, foreign currencies and certain anticipated future transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce that exposure and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly or quarterly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether similarly forecasted transactions are probable of occurring in the future.

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For certain of our physical forward derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with the physical contract transactions are recognized during the period when volumes are physically delivered or received. Physical derivative contracts are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar contracts are probable of physically delivering in the future.

See Note 4 for additional information regarding our derivative instruments and related interest rate and commodity hedging activities.

Estimates

Preparing our consolidated financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Income Tax Benefit

During the first quarter of 2012, we recognized a net income tax benefit of $34.4 million, which was primarily due to a $46.5 million net income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies partially offset by accruals for the Texas Margin Tax. The $46.5 million benefit is attributable to the difference between deferred income taxes accrued by the applicable subsidiaries through the date of conversion and any current income tax due in connection with the conversion.

Other Non-Operating Income

The following table presents the components of “Other, net” income for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Gain on sales of available-for-sale securities (1)	$53.3	$--
Distribution income from available-for-sale securities	4.1	--
Other	1.0	0.2
	$58.4	$0.2

(1) Represents gains on the sale of Energy Transfer Equity common units. See Note 7 for information regarding our investment in Energy Transfer Equity.

Recent Accounting Developments

Accounting standard setting organizations have been very active in recent years. Recently, they issued new and revised accounting guidance on a number of topics, including balance sheet offsetting. We do not believe that adoption of this new guidance will have a material impact on our consolidated financial statements.

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Note 3. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the expense we recognized in connection with equity-based awards for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Restricted common unit awards	$14.8	$11.4
Unit option awards	0.7	0.9
Other (1)	0.9	(0.5)
Total compensation expense	$16.4	$11.8

(1) Primarily consists of unit appreciation rights ("UARs"), phantom units and similar awards.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., UARs and phantom units) is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At March 31, 2012, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"). After giving effect to awards granted under the 1998 Plan and 2008 Plan through March 31, 2012, a total of 531,669 and 4,885,394 additional common units could be issued under these plans, respectively.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards issued in 2012 generally vest at a rate of 25% per year beginning one year after the grant date. As used in the context of EPCO's long-term incentive plans, the term "restricted common unit" represents a time-vested unit. Such awards are non-vested until the required service period expires. Restricted common units are included in the number of common units presented on our Unaudited Condensed Consolidated Balance Sheets.

The fair value of a restricted common unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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The following table presents information regarding restricted common unit awards for the period presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2011	3,868,216	$34.22
Granted (2)	1,529,438	$51.92
Vested (3)	(632,298)	$38.31
Forfeited	(24,800)	$36.33
Restricted common units at March 31, 2012	4,740,556	$39.37

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2012 was $79.4 million based on a grant date market price of $51.92 per unit. An estimated annual forfeiture rate of 3.25% was applied to these awards.
(3) Includes awards granted to the independent directors of the board of directors of Enterprise GP as part of their annual compensation for 2012. A total of 10,038 restricted common units were issued in February 2012 to the independent directors of Enterprise GP that immediately vested upon issuance.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid to limited partners. Since these restricted common units are participating securities, such distributions are included in "Cash distributions paid to limited partners" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Cash distributions paid to restricted common unit holders	$2.4	$2.1
Total intrinsic value of our restricted common unit awards vesting during period	32.6	14.7

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $107.5 million at March 31, 2012, of which our allocated share of the cost is currently estimated to be $102.2 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.2 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option grant may be no less than the market price of our common units on the date of grant. In general, option grants have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2011 will expire on December 31, 2012). However, unit options only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

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The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model. Compensation expense recorded in connection with unit options is based on the grant date fair value of such awards, net of an allowance for estimated forfeitures, over the requisite service or vesting period. The following table presents unit option activity for the period presented:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit options at December 31, 2011	3,753,420	$ 28.08	2.6	$ 11.1
Exercised	(712,280)	$ 30.76		
Unit options at March 31, 2012	3,041,140	$ 27.45	2.8	$ --
Options exercisable at March 31, 2012	--		--	--

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding our unit options during the periods presented:

	For the Three Months Ended March 31, 2012	2011
Total intrinsic value of unit option awards exercised during period	$ 14.0	$ --
Cash received from EPCO in connection with the exercise of unit option awards	10.2	--
Unit option-related reimbursements to EPCO	14.0	--

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $3.0 million at March 31, 2012, of which our allocated share of the cost is currently estimated to be $2.7 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.3 years.

Unit Appreciation Rights

UARs entitle the recipient to receive a cash payment on the vesting date of the award equal to the excess, if any, of the then current fair market value of our common units over the grant date fair value of the award. UARs are accounted for as liability awards.

At March 31, 2012 and December 31, 2011, there were 107,328 UARs outstanding that had been granted under the 2006 Plan. The accrued liability for UARs at March 31, 2012 and December 31, 2011 was $1.1 million and $0.5 million, respectively.

Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Substantially all of our derivatives are used for non-trading activities.

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We are required to recognize derivative instruments at fair value as either assets or liabilities on our balance sheet unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

Interest Rate Derivative Instruments

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. The following table summarizes our portfolio of interest rate swaps at March 31, 2012:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.5%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.6% to 2.0%	Mark-to-market

Interest expense for the three months ended March 31, 2012 and 2011 reflects a benefit of $2.8 million and $9.7 million, respectively, attributable to interest rate swaps.

In February 2012, we settled 11 fixed-to-floating interest rate swaps having an aggregate notional amount of $800.0 million, resulting in gains totaling $37.7 million. These gains will be amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period of approximately three years.

The following table summarizes our portfolio of forward starting swaps outstanding at March 31, 2012. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	7 forward starting swaps	$350.0	8/12	3.7%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

In connection with the issuance of Senior Notes EE in February 2012 (see Note 9), we settled ten forward starting swaps having an aggregate notional value of $500.0 million, resulting in losses totaling $115.3 million. These losses are reflected in other comprehensive income for the three months ended March 31, 2012 and amortized to earnings (as an increase in interest expense) using the effective interest method over the forecasted hedge period of ten years.

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Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at March 31, 2012:

	Volume (1)		Accounting
Derivative Purpose	Current (2)	Long-Term (2)	Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	27.7 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	2.4 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.3 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	3.2 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	10.5 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	3.7 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	3.6 MMBbls	0.2 MMBbls	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	0.4 MMBbls	n/a	Cash flow hedge
Forecasted sales of refined products	0.4 MMBbls	n/a	Cash flow hedge
Refined products inventory management activities	0.1 MMBbls	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.6 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	2.6 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (5,6)	416.9 Bcf	69.6 Bcf	Mark-to-market
Refined products risk management activities (6)	0.4 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	6.1 MMBbls	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2013, May 2012 and October 2015, respectively.
(3) PTR represents the British thermal unit ("Btu") equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.
(4) Forecasted sales of NGL volumes under natural gas processing exclude 4.9 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(5) Current volumes include approximately 104.2 Bcf of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory; and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion

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of our expected equity NGL production at fixed prices through December 2012, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on
Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	March 31, 2012		December 31, 2011		March 31, 2012		December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 14.7	Other current assets	$ 43.7	Other current liabilities	$ 146.5	Other current liabilities	$ 163.6
Interest rate derivatives	Other assets	22.7	Other assets	44.2	Other liabilities	--	Other liabilities	127.1
Total interest rate derivatives		37.4		87.9		146.5		290.7
Commodity derivatives	Other current assets	47.0	Other current assets	20.3	Other current liabilities	100.1	Other current liabilities	30.3
Commodity derivatives	Other assets	0.4	Other assets	--	Other liabilities	--	Other liabilities	0.2
Total commodity derivatives (1)		47.4		20.3		100.1		30.5
Total derivatives designated as hedging instruments		$ 84.8		$ 108.2		$ 246.6		$ 321.2
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 10.9	Other current liabilities	$ 10.1

Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	9.7	Other liabilities	10.6
Total interest rate derivatives		--		--		20.6		20.7
Commodity derivatives	Other current assets	37.2	Other current assets	34.4	Other current liabilities	16.9	Other current liabilities	32.5
Commodity derivatives	Other assets	5.3	Other assets	12.6	Other liabilities	2.4	Other liabilities	2.0
Total commodity derivatives		42.5		47.0		19.3		34.5
Total derivatives not designated as hedging instruments		$ 42.5		$ 47.0		$ 39.9		$ 55.2

(1) Represents commodity derivative instrument transactions that have either not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

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The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods presented:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative For the Three Months Ended March 31, 2012	2011
Interest rate derivatives	Interest expense	$ (1.5)	$ (12.3)
Commodity derivatives	Revenue	0.7	0.3
Total		$ (0.8)	$ (12.0)

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item For the Three Months Ended March 31, 2012	2011
Interest rate derivatives	Interest expense	$ 1.1	$ 11.3
Commodity derivatives	Revenue	0.4	(1.3)
Total		$ 1.5	$ 10.0

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations and Unaudited Condensed Statements of Consolidated Comprehensive Income for the periods presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income/(Loss) on Derivative (Effective Portion) For the Three Months Ended March 31, 2012	2011
Interest rate derivatives	$28.9	$14.1
Commodity derivatives – Revenue	(39.6)	(155.4)
Commodity derivatives – Operating costs and expenses	(20.0)	4.0
Total	$(30.7)	$(137.3)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/(Loss) to Income (Effective Portion) For the Three Months Ended March 31, 2012	2011

Interest rate derivatives	Interest expense	$(2.7)	$(1.5)
Commodity derivatives	Revenue	(10.0)	(69.2)
Commodity derivatives	Operating costs and expenses	(12.0)	0.3
Total		$(24.7)	$(70.4)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion) For the Three Months Ended March 31,	
		2012	2011
Commodity derivatives	Revenue	$ --	$ (0.1)
Commodity derivatives	Operating costs and expenses	0.3	--
Total		$ 0.3	$ (0.1)

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Over the next twelve months, we expect to reclassify $19.1 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $59.3 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $18.2 million as an increase in operating costs and expenses and $41.1 million as a decrease in revenue.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods presented:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative For the Three Months Ended March 31, 2012	2011
Interest rate derivatives	Interest expense	$(2.2)	$(2.1)
Commodity derivatives	Revenue	20.8	3.8
Commodity derivatives	Operating costs and expenses	(2.8)	--
Total		$15.8	$1.7

Fair Value Measurements

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk, in the principal market of the asset or liability at a specified measure date. Recognized valuation techniques employ inputs such as contractual prices, quoted market prices or rates, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

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The following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at March 31, 2012. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input that is significant to their respective fair value. Our assessment of the relative significance of such inputs requires judgment.

	At March 31, 2012			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Investment in equity securities – available-for-sale (1)	$119.8	$--	$ --	$119.8
Interest rate derivatives	--	37.4	--	37.4
Commodity derivatives	34.8	50.5	4.6	89.9
Total	$154.6	$87.9	$ 4.6	$247.1
Financial liabilities:				
Interest rate derivatives	$--	$167.1	$ --	$167.1
Commodity derivatives	89.9	25.8	3.7	119.4
Total	$89.9	$192.9	$ 3.7	$286.5

(1) See Note 7 for information related to our investment in Energy Transfer Equity common units, which trade on the NYSE under ticker symbol "ETE."

The following table sets forth a reconciliation of changes in the overall fair values of our Level 3 financial assets and liabilities for the periods presented:

		For the Three Months Ended March 31,	
	Location	2012	2011
Balance, January 1		$0.4	$(25.9)
Total gains (losses) included in:			
Net income (1)	Revenue	0.5	(0.5)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	0.5	16.2
Settlements		(0.5)	0.8
Transfers out of Level 3 (2)		--	9.8
Balance, March 31		$0.9	$0.4

(1) There were unrealized gains of $0.1 million and losses of $0.2 million included in these amounts for the three months ended March 31, 2012 and 2011, respectively.

(2) Transfers out of Level 3 into Level 2 during 2011 were primarily due to the change in observability of forward NGL prices.

The following table provides quantitative information about our Level 3 fair value measurements at March 31, 2012:

	Fair Value				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Propane	$0.6	$--	Discounted cash flow	Forward commodity price	$1.27 – $1.33 /gallon
Commodity derivatives – Crude Oil	3.9	3.6	Discounted cash flow	Forward commodity price	$103.02 – $104.66 /barrel
Commodity derivatives – Natural gas	0.1	0.1	Discounted cash flow	Forward commodity price	$2.11 – $2.22 /MMBtu
Total	$4.6	$3.7			

We believe certain forward commodity prices are the most significant unobservable inputs in determining our recurring Level 3 fair value measurements at March 31, 2012. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative

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depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our CEO with guidance and support from a risk management committee ("RMC"), which meets quarterly (or on a more frequent basis if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates forward curves used to determine the fair values of our Level 3 commodity derivatives. These forward curves are based on published indexes, market quotes or are derived from other available inputs.

Nonfinancial Assets and Liabilities

Using appropriate valuation techniques, we reduced the carrying value of certain assets recorded as property, plant and equipment to an estimated fair value of $0.5 million based on the present value of expected future cash flows (Level 3), resulting in nonrecurring fair value adjustments (i.e., non-cash asset impairment charges) totaling $5.4 million during the three months ended March 31, 2012. These impairment charges recorded during the first quarter 2012 were recorded to reflect assets that are no longer in use or to reduce the fair value to what we can expect to receive from anticipated sales. We did not record any non-cash asset impairment charges during the three months ended March 31, 2011.

The following table summarizes our non-cash impairment charges, which are a component of operating costs and expenses, by business segment during the three months ended March 31, 2012:

NGL Pipelines & Services	$5.1
Petrochemical & Refined Products Services	0.3
Total non-cash impairment charges	$5.4

Forecast data and other assumptions supporting the fair value of fixed assets being tested for impairment are based on the nonfinancial assets' highest and best use, which includes estimated probabilities where multiple outcomes are possible. Such probability weights are generally obtained from business management personnel having oversight responsibilities for the assets in question. Key commercial assumptions (e.g., anticipated operating margins, growth rates and timing of cash flows) and test results are certified by members of senior management.

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash), accounts receivable and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate long-term debt obligations was approximately $16.19 billion and $15.76 billion at March 31, 2012 and December 31, 2011, respectively. The aggregate carrying value of these debt obligations was $14.58 billion and $14.33 billion at March 31, 2012 and December 31, 2011, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

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Note 5. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	March 31, 2012	December 31, 2011
NGLs	$402.7	$563.6
Petrochemicals and refined products	433.4	443.4
Crude oil	58.7	39.2
Natural gas	39.3	65.5
Total	$934.1	$1,111.7

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties), these volumes are valued at market-based prices during the month in which they are acquired.

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 4 for a description of our commodity hedging activities.

The following table summarizes our cost of sales and lower of cost or market adjustments for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Cost of sales (1)	$9,665.8	$8,819.3
Lower of cost or market adjustments	5.9	1.2

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. Quarter-to-quarter fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

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Note 6. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	March 31, 2012	December 31, 2011
Plants, pipelines and facilities (1)	3-45 (6)	$22,567.2	$22,354.4
Underground and other storage facilities (2)	5-40 (7)	1,416.0	1,388.6
Platforms and facilities (3)	20-31	637.5	637.5
Transportation equipment (4)	3-10	153.1	151.5
Marine vessels (5)	15-30	633.5	615.9
Land		141.3	136.1
Construction in progress		2,810.8	2,145.6
Total		28,359.4	27,429.6
Less accumulated depreciation		5,449.1	5,238.0
Property, plant and equipment, net		$22,910.3	$22,191.6

(1) Plants and pipelines include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods presented:

	For the Three Months Ended March 31, 2012	2011
Depreciation expense (1)	$212.0	$186.5
Capitalized interest (2)	30.6	17.2

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) Capitalized interest reduces interest expense during the period it is recorded and increases the carrying value of the associated asset, which will subsequently increase depreciation expense once the asset is placed in service.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. The following table presents information regarding our AROs since December 31, 2011:

ARO liability balance, December 31, 2011	$112.0
Liabilities incurred during period	0.8
Liabilities settled during period	(1.6)
Revisions in estimated cash flows	3.4
Accretion expense	1.4
ARO liability balance, March 31, 2012	$116.0

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Property, plant and equipment at March 31, 2012 and December 31, 2011 includes $37.2 million and $37.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents our accretion expense forecasts for AROs for the periods presented:

Remainder of 2012	2013	2014	2015	2016
$4.0	$5.6	$6.0	$5.8	$6.1

Certain of our unconsolidated affiliates have AROs recorded at March 31, 2012 and December 31, 2011 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 7. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. Unless noted otherwise, we account for these investments using the equity method.

	Ownership Interest at March 31, 2012	March 31, 2012	December 31, 2011
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$34.8	$35.5
K/D/S Promix, L.L.C.	50%	41.6	40.7
Baton Rouge Fractionators LLC	32.2%	20.9	21.0
Skelly-Belvieu Pipeline Company, L.L.C.	50%	39.6	35.0
Texas Express Pipeline LLC	45%	49.8	13.9
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	3.9	4.4
White River Hub, LLC	50%	25.4	25.7
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline LLC	50%	164.6	170.7
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	52.7	55.4
Cameron Highway Oil Pipeline Company	50%	220.8	222.8
Deepwater Gateway, L.L.C.	50%	93.8	94.6
Neptune Pipeline Company, L.L.C.	25.7%	50.0	51.1
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	33.7	1.0
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	9.0	9.5
Centennial Pipeline LLC ("Centennial")	50%	51.4	51.8
Other (2)	Various	3.3	3.4
Other Investments:			
Energy Transfer Equity (3)	1.3%	--	1,023.1
Total		$895.3	$1,859.6

(1) Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.
(3) Effective January 18, 2012, our investment in Energy Transfer Equity common units is no longer accounted for using the equity method (see below).

At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of approximately $825.1 million and a gain on the sale of $27.5 million. Following the completion of the January 18 transaction, our ownership percentage in Energy Transfer Equity was below 3%, and we discontinued using the equity method to account for this investment and began accounting for the remaining units as an investment in available-for-sale equity securities. For the period January 1, 2012 to January 18, 2012, we recorded an estimated $2.4 million of equity earnings from Energy Transfer

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Equity, which is presented as a component of "Operating income." Following the January 18 transaction, we sold an additional 3,569,232 Energy Transfer Equity common units through March 31, which generated cash proceeds of approximately $150.8 million and aggregate gains on these sales of $25.8 million. Gains on the first quarter of 2012 sales are presented as a component of "Other income." Proceeds from these sales were used for general company purposes, including funding capital expenditures.

At March 31, 2012, we owned 2,971,646 common units of Energy Transfer Equity, which represented approximately 1.3% of its common units outstanding on April 3, 2012. The $119.8 million carrying value of these available-for-sale equity securities is a component of "Prepaid and other current assets" as presented on our Unaudited Condensed Consolidated Balance Sheet at March 31, 2012. Accumulated other comprehensive income (loss) at March 31, 2012 includes $15.8 million of unrealized gains related to these available-for-sale equity securities. We sold the remainder of our investment in Energy Transfer Equity in April 2012.

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
NGL Pipelines & Services	$5.2	$5.9
Onshore Natural Gas Pipelines & Services	1.4	1.2
Onshore Crude Oil Pipelines & Services	0.5	(0.5)
Offshore Pipelines & Services	6.9	8.3
Petrochemical & Refined Products Services	(6.5)	(5.0)
Other Investments (1)	2.4	6.3
Total	$9.9	$16.2

(1) With respect to the first quarter of 2012, amount presented reflects our estimated equity in the income of Energy Transfer Equity from January 1, 2012 to January 18, 2012.

The following table presents unamortized excess cost amounts by business segment at the dates indicated:

	March 31, 2012	December 31, 2011
NGL Pipelines & Services	$24.5	$24.7
Onshore Crude Oil Pipelines & Services	19.0	19.2
Offshore Pipelines & Services	14.5	14.8
Petrochemical & Refined Products Services	2.8	2.9
Other Investments (1)	--	1,119.0
Total	$60.8	$1,180.6

(1) On January 18, 2012, we discontinued using the equity method to account for our investment in Energy Transfer Equity common units and began accounting for them as available-for-sale equity securities. As a result, we no longer have any excess cost amounts associated with this investment.

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The following table presents our amortization of excess cost amounts by business segment for the periods presented:

	For the Three Months Ended March 31, 2012	2011
NGL Pipelines & Services	$0.2	$0.3
Onshore Crude Oil Pipelines & Services	0.2	0.2
Offshore Pipelines & Services	0.3	0.3
Petrochemical & Refined Products Services	0.1	--
Other Investments (1)	0.3	9.1
Total	$1.1	$9.9

(1) Reflects amortization of excess cost amounts related to our investment in Energy Transfer Equity through January 18, 2012. We ceased using the equity method to account for this investment on January 18, 2012.

In April 2012, we, along with Anadarko Petroleum Corporation and DCP Midstream, LLC formed a new joint venture, Front Range Pipeline LLC ("Front Range"), to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend approximately 435 miles to Skellytown in Carson County, Texas. Each party holds a one-third ownership interest in the joint venture. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, is expected to provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. Depending on shipper interest in a binding open commitment period that commenced in April 2012, initial capacity on the Front Range Pipeline is expected to be approximately 150 MBPD, which can be readily expanded to approximately 230 MBPD. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

Summarized Income Statement Information of Unconsolidated Affiliates

The following table presents unaudited income statement information (on a 100% basis) of our unconsolidated affiliates, aggregated by the business segments to which they relate, for the periods presented:

	Summarized Income Statement Information for the Three Months Ended March 31, 2012			March 31, 2011		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$110.9	$27.0	$27.0	$100.1	$23.4	$23.4
Onshore Natural Gas Pipelines & Services	30.9	2.6	2.6	35.5	2.6	2.6
Onshore Crude Oil Pipelines & Services	12.3	0.8	0.8	11.2	0.5	0.5
Offshore Pipelines & Services	41.1	19.1	18.4	46.3	18.9	18.7
Petrochemical & Refined Products Services	5.4	(9.4)	(11.4)	10.1	(7.0)	(9.2)
Other Investments (1)	--	--	--	1,989.1	364.2	88.6

(1) On January 18, 2012, we discontinued using the equity method to account for our investment in Energy Transfer Equity common units. As such, income statement data for Energy Transfer Equity is not presented for the three months ended March 31, 2012. For the three months ended March 31, 2011, net income for Energy Transfer Equity

represents net income attributable to their partners.

The credit agreements of Poseidon and Centennial restrict their ability to pay cash dividends if a default or event of default (as defined in each credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. These businesses were in compliance with the terms of their credit agreements at March 31, 2012.

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Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by business segment at the dates indicated:

	March 31, 2012			December 31, 2011		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$340.8	$(133.0)	$207.8	$340.8	$(128.2)	$212.6
Contract-based intangibles	284.7	(142.4)	142.3	298.4	(169.7)	128.7
Segment total	625.5	(275.4)	350.1	639.2	(297.9)	341.3
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(220.2)	943.4	1,163.6	(209.7)	953.9
Contract-based intangibles	466.1	(296.2)	169.9	464.8	(290.9)	173.9
Segment total	1,629.7	(516.4)	1,113.3	1,628.4	(500.6)	1,127.8
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.7	(4.3)	5.4	9.7	(4.1)	5.6
Contract-based intangibles	0.4	(0.2)	0.2	0.4	(0.2)	0.2
Segment total	10.1	(4.5)	5.6	10.1	(4.3)	5.8
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(131.8)	74.0	205.8	(129.2)	76.6
Contract-based intangibles	1.2	(0.3)	0.9	1.2	(0.3)	0.9
Segment total	207.0	(132.1)	74.9	207.0	(129.5)	77.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(29.6)	74.7	104.3	(28.4)	75.9
Contract-based intangibles	55.5	(29.9)	25.6	57.6	(29.7)	27.9
Segment total	159.8	(59.5)	100.3	161.9	(58.1)	103.8
Total all segments	$2,632.1	$(987.9)	$1,644.2	$2,646.6	$(990.4)	$1,656.2

The following table presents the amortization expense of our intangible assets by business segment for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
NGL Pipelines & Services	$10.2	$10.4
Onshore Natural Gas Pipelines & Services	15.8	19.9

Onshore Crude Oil Pipelines & Services	0.2	0.1
Offshore Pipelines & Services	2.6	3.0
Petrochemical & Refined Products Services	3.5	4.3
Total	$32.3	$37.7

The following table presents forecasted amortization expense associated with existing intangible assets for the years presented:

Remainder of 2012	2013	2014	2015	2016
$89.8	$110.7	$107.0	$106.5	$107.6

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. There have been no changes to our goodwill amounts since those reported in our 2011 Form 10-K.

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Note 9. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	March 31, 2012	December 31, 2011
EPO senior debt obligations:		
Senior Notes S, 7.625% fixed-rate, due February 2012	$--	$490.5
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	500.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes T, 6.125% fixed-rate, due February 2013	182.5	182.5
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	400.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due September 2016	--	150.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	--	9.5
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	17.5	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	12.4	12.4
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	13,050.0	12,950.0
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2

Total principal amount of senior and junior debt obligations	14,582.7	14,482.7
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (1)	35.2	73.8
Unamortized discounts, net of premiums	(33.0)	(30.0)
Unamortized deferred net gains related to terminated interest rate swaps (1)	35.9	2.9
Total other, non-principal amounts	38.1	46.7
Less current maturities of debt (2)	(1,050.0)	(500.0)
Total long-term debt	$13,570.8	$14,029.4

(1) See Note 4 for information regarding our interest rate hedging activities.

(2) We expect to refinance the current maturities of our debt obligations prior to their maturity.

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The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at March 31, 2012 for the next five years, and in total thereafter:

	Scheduled Maturities of Debt						
	Total	Remainder of 2012	2013	2014	2015	2016	After 2016
Revolving Credit Facility	$--	$--	$--	$--	$--	$--	$--
Senior Notes	13,050.0	500.0	1,200.0	1,150.0	650.0	750.0	8,800.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$14,582.7	$500.0	$1,200.0	$1,150.0	$650.0	$750.0	$10,332.7

Apart from that discussed below and routine fluctuations in the balance of our revolving credit facility, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2011 Form 10-K.

Issuance of Senior Notes EE.

In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE at 99.542% of their principal amount. Senior Notes EE have a fixed interest rate of 4.85% and mature on August 15, 2042. Enterprise guarantees the notes through an unconditional guarantee on an unsecured and unsubordinated basis. Net proceeds from the issuance of Senior Notes EE were used to repay outstanding amounts on the maturity of our $490.5 million principal amount of Senior Notes S due February 2012 and our $9.5 million principal amount of TEPPCO Senior Notes due February 2012 and for general company purposes.

Senior Notes EE rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes EE are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Letters of Credit

At March 31, 2012, EPO had $77.5 million in letters of credit outstanding related to its commodity derivative instruments. These letters of credit do not reduce the amount available for borrowing under EPO's $3.5 Billion Multi-Year Revolving Credit Facility.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at March 31, 2012.

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Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligation during the three months ended March 31, 2012:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.62% to 1.67%	1.66%

Note 10. Equity and Distributions

Our partners' equity reflects the various classes of limited partner interests of Enterprise (e.g., common units (including restricted common units) and Class B units). The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2011:

	Common Units	Class B Units	Treasury Units
Balance, December 31, 2011	881,620,418	4,520,431	--
Common units issued in connection with DRIP and EUPP	691,936	--	--
Common units issued in connection with equity-based awards	201,925	--	--
Restricted common units issued	1,529,438	--	--
Forfeiture of restricted common units	(24,800)	--	--
Acquisition of treasury units in connection with equity-based awards	(187,343)	--	187,343
Cancellation of treasury units	--	--	(187,343)
Balance, March 31, 2012	883,831,574	4,520,431	--

During the three months ended March 31, 2012, 632,298 restricted common units vested and converted to common units. Of this amount, 187,343 were sold back to us by employees to cover related withholding tax requirements. We cancelled such treasury units immediately upon acquisition.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO utilized the 2010 Shelf to issue its Senior Notes EE in February 2012 (see Note 9).

In March 2012, we filed a registration statement with the SEC authorizing the issuance of up to $1.0 billion in our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of March 31, 2012, we have not issued any common units under this registration statement.

We have also filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 of our common units in connection with a distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. After taking into account the number of common units issued under these registration statements through March 31, 2012, Enterprise may issue an additional 25,506,188 common units under its DRIP. A total of 667,095 common units were issued during the first quarter of 2012 under our DRIP, which generated net cash proceeds of $31.8 million.

Enterprise has a registration statement on file with the SEC authorizing the issuance of 440,879 common units under the Enterprise employee unit purchase plan ("EUPP"). After taking into account the number of common units issued under this registration statement through March 31, 2012, Enterprise may issue an additional 405,864 common units under its EUPP. During the first quarter of 2012, Enterprise

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issued 24,841 common units under the Enterprise EUPP, which generated net cash proceeds of $1.2 million.

The net cash proceeds received during the first quarter of 2012 from Enterprise's DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's revolving credit facility and for general company purposes.

Accumulated Other Comprehensive Income (Loss)

Our accumulated other comprehensive income (loss) primarily include the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Amounts accumulated in other comprehensive income (loss) related to cash flow hedges are reclassified into earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified into earnings.

The following table presents the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	March 31, 2012	December 31, 2011
Commodity derivative instruments (1)	$(59.0)	$(21.4)
Interest rate derivative instruments (1)	(297.4)	(329.0)
Foreign currency translation adjustment (2)	1.7	1.7
Pension and postretirement benefit plans	(2.9)	(1.7)
Proportionate share of other comprehensive loss of Energy Transfer Equity	--	(1.0)
Unrealized gain on investment in available-for-sale equity securities (3)	15.8	--
Total accumulated other comprehensive loss in partners' equity	$(341.8)	$(351.4)

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) Relates to our investment in Energy Transfer Equity common units, which is accounted for as available-for-sale at March 31, 2012. This investment was accounted for using the equity method at December 31, 2011 through January 18, 2012.

Noncontrolling Interests

Prior to the completion of the Duncan Merger, effective September 6, 2011, we accounted for the former owners' interest in Duncan Energy Partners as noncontrolling interest. Under this method of presentation, all pre-Duncan Merger revenues and expenses of Duncan Energy Partners are included in net income, and the former owners' share of the income of Duncan Energy Partners is a component of "Net income attributable to noncontrolling interests" as reflected on our Unaudited Condensed Statements of Consolidated Operations.

Additionally, cash distributions paid to and cash contributions received from the former owners of Duncan Energy Partners are reflected as a component of cash distributions paid to and cash contributions received from noncontrolling interests.

The following table presents additional information regarding noncontrolling interests as presented on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	March 31, 2012	December 31, 2011
Joint venture partners (1)	$ 109.5	$ 105.9

(1) Represents third party ownership interests in joint ventures that we consolidate, including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company and Wilprise Pipeline Company LLC.

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The following table presents the components of net income attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Former owners of Duncan Energy Partners	$--	$7.9
Joint venture partners	4.2	5.9
Total	$4.2	$13.8

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Cash distributions paid to noncontrolling interests:		
Former owners of Duncan Energy Partners	$--	$10.9
Joint venture partners	6.6	6.3
Total cash distributions paid to noncontrolling interests	$6.6	$17.2
Cash contributions from noncontrolling interests:		
Former owners of Duncan Energy Partners	$--	$0.6
Joint venture partners	4.9	0.7
Total cash contributions from noncontrolling interests	$4.9	$1.3

Cash distributions paid to the limited partners of Duncan Energy Partners (prior to the Duncan Merger) represent the quarterly cash distributions paid to its unitholders. Similarly, cash contributions received from the limited partners of Duncan Energy Partners (prior to the Duncan Merger) represent net cash proceeds received from the issuance of limited partner units.

Cash Distributions

The following table presents our declared quarterly cash distribution rates with respect to the quarter indicated:

	Distribution Per Common Unit	Record Date	Payment Date
2012			
1st Quarter	$0.6275	04/30/12	05/09/12

In connection with the merger of Enterprise and Enterprise GP Holdings L.P. during 2010, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units (the "Designated Units") it owned over a five-year period after the merger closing date of November 22, 2010. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions paid or to be paid, if any, during the following calendar years: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. Accordingly, distributions paid to partners during calendar year 2012 exclude 26,130,000 Designated Units.

Note 11. Business Segments

We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. Our business

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segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we did not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a standalone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

The following table shows our measurement of total segment gross operating margin for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Revenues	$11,252.5	$10,183.7
Less: Operating costs and expenses	(10,467.2)	(9,537.1)
Add: Equity in income of unconsolidated affiliates	9.9	16.2
Depreciation, amortization and accretion in operating costs and expenses (1)	254.6	230.8
Non-cash asset impairment charges	5.4	--
Operating lease expenses paid by EPCO	--	0.2
Gains from asset sales and related transactions in operating costs and expenses (2)	(2.5)	(18.4)
Total segment gross operating margin	$1,052.7	$875.4

(1) Amount is a component of “Depreciation, amortization and accretion” as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.

(2) Amount is a component of "Gains from asset sales and related transactions" as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.

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The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before income taxes for the periods presented:

	For the Three Months Ended March 31, 2012	2011
Total segment gross operating margin	$1,052.7	$875.4
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(254.6)	(230.8)
Non-cash asset impairment charges	(5.4)	--
Operating lease expenses paid by EPCO	--	(0.2)
Gains from asset sales and related transactions in operating costs and expenses	2.5	18.4
General and administrative costs	(46.3)	(37.9)
Operating income	748.9	624.9
Other expense, net	(127.8)	(183.3)
Income before income taxes	$621.1	$441.6

Information by business segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Business Segments: NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:								
Three months ended March 31, 2012	$ 4,354.1	$ 804.9	$ 4,473.6	$ 54.4	$ 1,534.7	$ --	$ --	$ 11,221.7
Three months ended March 31, 2011	4,055.4	871.7	3,370.6	60.6	1,575.3	--	--	9,933.6
Revenues from related parties:								
Three months ended March 31, 2012	0.4	28.7	--	1.7	--	--	--	30.8
Three months ended March 31, 2011	201.4	44.9	--	3.8	--	--	--	250.1
Intersegment and intrasegment revenues:								
	2,818.2	223.7	1,730.9	3.3	439.9	--	(5,216.0)	--

Three months ended March 31, 2012								
Three months ended March 31, 2011	3,474.6	270.9	707.1	1.7	473.1	--	(4,927.4)	--
Total revenues:								
Three months ended March 31, 2012	7,172.7	1,057.3	6,204.5	59.4	1,974.6	--	(5,216.0)	11,252.5
Three months ended March 31, 2011	7,731.4	1,187.5	4,077.7	66.1	2,048.4	--	(4,927.4)	10,183.7
Equity in income (loss) of unconsolidated affiliates:								
Three months ended March 31, 2012	5.2	1.4	0.5	6.9	(6.5)	2.4	--	9.9
Three months ended March 31, 2011	5.9	1.2	(0.5)	8.3	(5.0)	6.3	--	16.2
Gross operating margin:								
Three months ended March 31, 2012	654.9	206.2	39.3	52.1	97.8	2.4	--	1,052.7
Three months ended March 31, 2011	504.4	159.2	31.8	61.3	112.4	6.3	--	875.4
Segment assets:								
At March 31, 2012	8,014.1	9,984.9	960.1	2,007.7	3,764.5	--	2,810.8	27,542.1
At December 31, 2011	7,966.4	9,949.6	944.6	2,000.9	3,769.5	1,023.1	2,145.6	27,799.7
Property, plant and equipment, net: (see Note 6)								
At March 31, 2012	7,136.1	8,546.0	478.7	1,399.7	2,539.0	--	2,810.8	22,910.3
At December 31, 2011	7,137.8	8,495.4	456.9	1,416.4	2,539.5	--	2,145.6	22,191.6
Investments in unconsolidated affiliates: (see Note 7)								
At March 31, 2012	186.7	29.3	164.6	451.0	63.7	--	--	895.3
At December 31, 2011	146.1	30.1	170.7	424.9	64.7	1,023.1	--	1,859.6

Intangible assets, net: (see Note 8)								
At March 31, 2012	350.1	1,113.3	5.6	74.9	100.3	--	--	1,644.2
At December 31, 2011	341.3	1,127.8	5.8	77.5	103.8	--	--	1,656.2
Goodwill: (see Note 8)								
At March 31, 2012	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3
At December 31, 2011	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3

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During the first quarter of 2012, we sold 26,331,868 of the common units we owned of Energy Transfer Equity and sold the remaining units in April 2012. Our reporting for the Other Investments segment ceased on January 18, 2012, when we discontinued using the equity method to account for this investment and began accounting for the remaining units as available-for-sale securities. See Note 7 for additional information regarding our investment in Energy Transfer Equity and related sales.

The following table provides additional information regarding our consolidated revenues and costs and expenses for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
NGL Pipelines & Services:		
Sales of NGLs and related products	$4,115.3	$4,057.7
Midstream services	239.2	199.1
Total	4,354.5	4,256.8
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	572.6	712.7
Midstream services	261.0	203.9
Total	833.6	916.6
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,447.6	3,348.2
Midstream services	26.0	22.4
Total	4,473.6	3,370.6
Offshore Pipelines & Services:		
Sales of natural gas	0.1	0.3
Sales of crude oil	1.4	3.3
Midstream services	54.6	60.8
Total	56.1	64.4
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,351.2	1,382.8
Midstream services	183.5	192.5
Total	1,534.7	1,575.3
Total consolidated revenues	$11,252.5	$10,183.7
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales related to our marketing activities	$8,688.5	$7,930.1
Depreciation, amortization and accretion	254.6	230.8
Gains from asset sales and related transactions	(2.5)	(18.4)
Non-cash asset impairment charges	5.4	--
Other operating costs and expenses	1,521.2	1,394.6
General and administrative costs	46.3	37.9
Total consolidated costs and expenses	$10,513.5	$9,575.0

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of NGLs, natural gas, crude oil, petrochemicals and refined products; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise.

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Note 12. Related Party Transactions

The following table summarizes our related party transactions for the periods presented:

	For the Three Months Ended March 31, 2012	2011
Revenues – related parties:		
Energy Transfer Equity and subsidiaries	$--	$210.2
Other unconsolidated affiliates	30.8	39.9
Total revenue – related parties	$30.8	$250.1
Costs and expenses – related parties:		
EPCO and affiliates	$166.0	$173.0
Energy Transfer Equity and subsidiaries	--	267.4
Other unconsolidated affiliates	5.1	10.2
Total costs and expenses – related parties	$171.1	$450.6

Effective with the first quarter of 2012, we no longer report Energy Transfer Equity and its subsidiaries as related parties. See Note 7 for information related to the sale of Energy Transfer Equity common units.

The following table summarizes our related party accounts receivable and accounts payable amounts at the dates indicated:

	March 31, 2012	December 31, 2011
Accounts receivable - related parties:		
Energy Transfer Equity and subsidiaries	$--	$28.4
Other unconsolidated affiliates	13.4	15.1
Total accounts receivable – related parties	$13.4	$43.5
Accounts payable - related parties:		
EPCO and affiliates	$53.2	$108.3
Energy Transfer Equity and subsidiaries	--	92.6
Other unconsolidated affiliates	26.1	10.7
Total accounts payable – related parties	$79.3	$211.6

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our sole general partner), which entities are not a part of our consolidated group of companies.

EPCO is a privately held company controlled collectively by the EPCO Trustees. At March 31, 2012, EPCO and its affiliates (including Dan Duncan LLC and two Duncan family trusts, the beneficiaries of which include the estate of

Mr. Duncan) beneficially owned the following limited partner interests in us:

Number of Units	Percentage of Outstanding Units
338,930,881 (1)	38.2%

(1) Includes 4,520,431 Class B units.

Dan Duncan LLC owns 100% of our general partner, Enterprise GP.

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We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other operations and to meet their debt obligations. During the three months ended March 31, 2012 and 2011, we paid EPCO and its privately held affiliates cash distributions of $183.7 million and $172.1 million, respectively.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods presented:

	For the Three Months Ended March 31,	
	2012	2011
Operating costs and expenses	$ 142.7	$ 147.4
General and administrative expenses	23.3	25.6
Total costs and expenses	$ 166.0	$ 173.0

Note 13. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss attributable to our limited partners by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 10) to the extent that such units do not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

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The following table presents our calculation of basic and diluted earnings per unit for the periods presented:

	For the Three Months Ended March 31, 2012	2011
BASIC EARNINGS PER UNIT		
Numerator:		
Net income attributable to limited partners	$651.3	$420.7
Denominator:		
Common units	852.3	809.9
Time-vested restricted common units	4.3	4.0
Total	856.6	813.9
Basic earnings per unit:		
Net income attributable to limited partners	$0.76	$0.52
DILUTED EARNINGS PER UNIT		
Numerator:		
Net income attributable to limited partners	$651.3	$420.7
Denominator:		
Common units	852.3	809.9
Time-vested restricted common units	4.3	4.0
Class B units	4.5	4.5
Designated Units	26.1	30.6
Incremental option units	1.5	1.3
Total	888.7	850.3
Diluted earnings per unit:		
Net income attributable to limited partners	$0.73	$0.49

Note 14. Commitments and Contingencies

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings.We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances (including the availability of insurance coverage), we do not believe the ultimate outcome of any currently pending lawsuit against us will have a material impact on our financial statements individually or in the aggregate.

At March 31, 2012 and December 31, 2011, litigation accruals on an undiscounted basis of $16.3 million and $16.5 million, respectively, were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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Contractual Obligations

Scheduled Maturities of Long-Term Debt. With the exception of (i) routine fluctuations in the balance of our revolving credit facility, (ii) the issuance of Senior Notes EE in February 2012 and (iii) the repayment of Senior Notes S and TEPPCO Senior Notes in February 2012, there have been no significant changes in our consolidated debt obligations since those reported in our 2011 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Consolidated lease and rental expense was $22.4 million and $20.5 million during the three months ended March 31, 2012 and 2011, respectively. There have been no material changes in our operating lease commitments since those reported in our 2011 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2011 Form 10-K.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of March 31, 2012, our contingent claims against such parties were approximately $38.3 million and claims against us were approximately $41.4 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time; however, in our opinion, the likelihood of a material impact on our Unaudited Condensed Consolidated Financial Statements from such disputes is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our Unaudited Condensed Consolidated Financial Statements.

Note 15. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts for the periods presented:

	For the Three Months Ended March 31, 2012	2011
Decrease (increase) in:		
Accounts receivable – trade	$(25.6)	$(81.2)
Accounts receivable – related parties	30.0	(8.1)
Inventories	135.6	357.2
Prepaid and other current assets	14.1	25.8
Other assets	(16.4)	(11.8)
Increase (decrease) in:		
Accounts payable – trade	63.4	28.0
Accounts payable – related parties	(132.2)	5.7
Accrued product payables	(195.7)	(114.8)
Accrued interest	(103.6)	(71.6)
Other current liabilities	40.7	(9.3)

Other liabilities	(11.4)	0.1
Net effect of changes in operating accounts	$(201.1)	$120.0

We incurred liabilities for construction in progress that had not been paid at March 31, 2012 and December 31, 2011 of $273.0 million and $286.9 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. These cash receipts are presented as “Contributions in aid of construction costs” within the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

Proceeds from asset sales and related transactions increased $914.0 million quarter-to-quarter, primarily from the sale of 26,331,868 common units of Energy Transfer Equity during the first quarter of 2012. See Note 7 for information regarding our investment in Energy Transfer Equity.

See Note 10 for information regarding cash amounts attributable to noncontrolling interests.

Note 16. Condensed Consolidating Financial Information

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. EPO’s consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 9 for additional information regarding our consolidated debt obligations.

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Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
March 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 144.1	$ 31.8	$ (5.5)	$ 170.4	$ --	$ (0.3)	$ 170.1
Accounts receivable – trade, net	1,517.4	3,018.1	(8.8)	4,526.7	--	--	4,526.7
Accounts receivable – related parties	221.4	1,557.2	(1,752.5)	26.1	(12.7)	--	13.4
Inventories	788.6	147.6	(2.1)	934.1	--	--	934.1
Prepaid and other current assets	147.5	309.1	(4.1)	452.5	0.4	--	452.9
Total current assets	2,819.0	5,063.8	(1,773.0)	6,109.8	(12.3)	(0.3)	6,097.2
Property, plant and equipment, net	1,504.0	21,415.8	(9.5)	22,910.3	--	--	22,910.3
Investments in unconsolidated affiliates	26,410.1	7,485.5	(33,000.3)	895.3	12,291.4	(12,291.4)	895.3
Intangible assets, net	158.5	1,499.1	(13.4)	1,644.2	--	--	1,644.2
Goodwill	458.9	1,633.4	--	2,092.3	--	--	2,092.3
Other assets	122.7	128.5	2.1	253.3	0.1	--	253.4
Total assets	$ 31,473.2	$ 37,226.1	$ (34,794.1)	$ 33,905.2	$ 12,279.2	$ (12,291.7)	$ 33,892.7
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,032.6	$ 17.4	$ --	$ 1,050.0	$ --	$ --	$ 1,050.0
Accounts payable – trade	312.2	565.2	(5.5)	871.9	0.4	(0.3)	872.0
Accounts payable – related parties	1,683.8	147.8	(1,752.3)	79.3	--	--	79.3
Accrued product payables	1,911.6	2,929.9	(11.1)	4,830.4	--	--	4,830.4
Accrued interest	183.6	0.9	--	184.5	--	--	184.5
Other current liabilities	332.6	351.9	(4.1)	680.4	--	--	680.4

Total current liabilities	5,456.4	4,013.1	(1,773.0)	7,696.5	0.4	(0.3)	7,696.6
Long-term debt	13,543.5	27.3	--	13,570.8	--	--	13,570.8
Deferred tax liabilities	5.7	15.1	2.1	22.9	--	(0.9)	22.0
Other long-term liabilities	26.8	188.2	--	215.0	--	--	215.0
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	12,440.8	28,208.1	(28,374.0)	12,274.9	12,278.8	(12,274.9)	12,278.8
Noncontrolling interests	--	4,774.3	(4,649.2)	125.1	--	(15.6)	109.5
Total equity	12,440.8	32,982.4	(33,023.2)	12,400.0	12,278.8	(12,290.5)	12,388.3
Total liabilities and equity	$ 31,473.2	$ 37,226.1	$ (34,794.1)	$ 33,905.2	$ 12,279.2	$ (12,291.7)	$ 33,892.7

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 48.2	$ 21.3	$ (11.2)	$ 58.3	$ --	$ --	$ 58.3
Accounts receivable – trade, net	1,599.4	2,913.2	(10.8)	4,501.8	--	--	4,501.8
Accounts receivable – related parties	141.1	2,155.5	(2,252.0)	44.6	(1.1)	--	43.5
Inventories	943.6	170.5	(2.4)	1,111.7	--	--	1,111.7
Prepaid and other current assets	216.8	152.6	(16.0)	353.4	--	--	353.4
Total current assets	2,949.1	5,413.1	(2,292.4)	6,069.8	(1.1)	--	6,068.7
Property, plant and equipment, net	1,477.5	20,723.7	(9.6)	22,191.6	--	--	22,191.6
Investments in unconsolidated affiliates	27,060.0	8,266.7	(33,467.1)	1,859.6	12,114.5	(12,114.5)	1,859.6
Intangible assets, net	142.4	1,527.4	(13.6)	1,656.2	--	--	1,656.2
Goodwill	458.9	1,633.4	--	2,092.3	--	--	2,092.3
Other assets	146.4	107.5	2.8	256.7	--	--	256.7
Total assets	$ 32,234.3	$ 37,671.8	$ (35,779.9)	$ 34,126.2	$ 12,113.4	$ (12,114.5)	$ 34,125.1
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 500.0	$ --	$ --	$ 500.0	$ --	$ --	$ 500.0
Accounts payable – trade	205.6	578.6	(11.2)	773.0	--	--	773.0
Accounts payable – related parties	2,407.2	71.9	(2,267.5)	211.6	--	--	211.6
Accrued product payables	2,141.0	2,912.4	(6.3)	5,047.1	--	--	5,047.1
Accrued interest	287.1	1.0	--	288.1	--	--	288.1
Other current liabilities	298.1	321.8	(7.4)	612.5	--	0.1	612.6

Total current liabilities	5,839.0	3,885.7	(2,292.4)	7,432.3	--	0.1	7,432.4
Long-term debt	13,975.1	54.3	--	14,029.4	--	--	14,029.4
Deferred tax liabilities	22.2	67.1	2.8	92.1	--	(0.9)	91.2
Other long-term liabilities	155.3	197.5	--	352.8	--	--	352.8
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	12,242.7	28,799.8	(28,946.4)	12,096.1	12,113.4	(12,096.1)	12,113.4
Noncontrolling interests	--	4,667.4	(4,543.9)	123.5	--	(17.6)	105.9
Total equity	12,242.7	33,467.2	(33,490.3)	12,219.6	12,113.4	(12,113.7)	12,219.3
Total liabilities and equity	$ 32,234.3	$ 37,671.8	$ (35,779.9)	$ 34,126.2	$ 12,113.4	$ (12,114.5)	$ 34,125.1

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 7,639.8	$ 7,158.5	$ (3,545.8)	$ 11,252.5	$ --	$ --	$ 11,252.5
Costs and expenses:							
Operating costs and expenses	7,409.8	6,603.6	(3,546.2)	10,467.2	--	--	10,467.2
General and administrative costs	15.4	30.7	--	46.1	0.2	--	46.3
Total costs and expenses	7,425.2	6,634.3	(3,546.2)	10,513.3	0.2	--	10,513.5
Equity in income of unconsolidated affiliates	594.5	78.4	(663.0)	9.9	651.5	(651.5)	9.9
Operating income	809.1	602.6	(662.6)	749.1	651.3	(651.5)	748.9
Other income (expense):							
Interest expense	(185.6)	(0.9)	--	(186.5)	--	--	(186.5)
Other, net	0.1	58.6	--	58.7	--	--	58.7
Total other expense, net	(185.5)	57.7	--	(127.8)	--	--	(127.8)
Income before income taxes	623.6	660.3	(662.6)	621.3	651.3	(651.5)	621.1
Benefit from income taxes	27.0	7.4	--	34.4	--	--	34.4
Net income	650.6	667.7	(662.6)	655.7	651.3	(651.5)	655.5
Net loss (income) attributable to noncontrolling interests	--	(44.4)	39.7	(4.7)	--	0.5	(4.2)
Net income attributable to entity	$ 650.6	$ 623.3	$ (622.9)	$ 651.0	$ 651.3	$ (651.0)	$ 651.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended March 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer	Other Subsidiaries	EPO and Subsidiaries	Consolidated EPO and	Enterprise Products	Eliminations and	Consolidated Total

	(EPO)	(Non-guarantor)	Eliminations and Adjustments	Subsidiaries	Partners L.P. (Guarantor)	Adjustments	
Revenues	$ 8,324.8	$ 6,078.7	$ (4,219.8)	$ 10,183.7	$ --	$ --	$ 10,183.7
Costs and expenses:							
Operating costs and expenses	8,178.2	5,578.6	(4,219.7)	9,537.1	--	--	9,537.1
General and administrative costs	0.9	33.7	--	34.6	3.3	--	37.9
Total costs and expenses	8,179.1	5,612.3	(4,219.7)	9,571.7	3.3	--	9,575.0
Equity in income of unconsolidated affiliates	458.0	31.8	(473.6)	16.2	424.0	(424.0)	16.2
Operating income	603.7	498.2	(473.7)	628.2	420.7	(424.0)	624.9
Other income (expense):							
Interest expense	(179.0)	(6.7)	1.9	(183.8)	--	--	(183.8)
Other, net	2.0	0.4	(1.9)	0.5	--	--	0.5
Total other expense, net	(177.0)	(6.3)	--	(183.3)	--	--	(183.3)
Income before income taxes	426.7	491.9	(473.7)	444.9	420.7	(424.0)	441.6
Provision for income taxes	(2.8)	(4.3)	--	(7.1)	--	--	(7.1)
Net income	423.9	487.6	(473.7)	437.8	420.7	(424.0)	434.5
Net loss (income) attributable to noncontrolling interests	--	(3.4)	(10.7)	(14.1)	--	0.3	(13.8)
Net income attributable to entity	$ 423.9	$ 484.2	$ (484.4)	$ 423.7	$ 420.7	$ (423.7)	$ 420.7

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 679.8	$ 648.1	$ (662.6)	$ 665.3	$ 651.3	$ (651.5)	$ 665.1
Comprehensive income attributable to noncontrolling interests	--	(44.4)	39.7	(4.7)	--	0.5	(4.2)
Comprehensive income attributable to entity	$ 679.8	$ 603.7	$ (622.9)	$ 660.6	$ 651.3	$ (651.0)	$ 660.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 435.1	$ 408.8	$ (473.7)	$ 370.2	$ 420.7	$ (424.0)	$ 366.9
Comprehensive income attributable to noncontrolling interests	--	(3.4)	(10.7)	(14.1)	--	0.3	(13.8)
Comprehensive income attributable to entity	$ 435.1	$ 405.4	$ (484.4)	$ 356.1	$ 420.7	$ (423.7)	$ 353.1

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 650.6	$ 667.7	$ (662.6)	$ 655.7	$ 651.3	$ (651.5)	$ 655.5
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	33.0	233.4	(0.3)	266.1	--	--	266.1
Equity in income of unconsolidated affiliates	(594.5)	(78.4)	663.0	(9.9)	(651.5)	651.5	(9.9)
Distributions received from unconsolidated affiliates	10.0	25.8	(8.8)	27.0	531.6	(531.6)	27.0
Net effect of changes in operating accounts and other operating activities	(489.4)	335.8	(191.4)	(345.0)	11.5	(0.3)	(333.8)
Net cash flows provided by operating activities	(390.3)	1,184.3	(200.1)	593.9	542.9	(531.9)	604.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(16.0)	(952.1)	--	(968.1)	--	--	(968.1)
Proceeds from asset sales	976.1	22.1	--	998.2	--	--	998.2
Other investing activities	(38.9)	(39.2)	12.5	(65.6)	(31.8)	31.8	(65.6)
Cash used in investing activities	921.2	(969.2)	12.5	(35.5)	(31.8)	31.8	(35.5)
Financing activities:							
Borrowings under debt agreements	1,396.6	--	--	1,396.6	--	--	1,396.6
Repayments of debt	(1,290.5)	(9.5)	--	(1,300.0)	--	--	(1,300.0)

Cash distributions paid to partners	(531.6)	(208.0)	208.0	(531.6)	(530.4)	531.6	(530.4)
Cash distributions paid to noncontrolling interests	--	(4.4)	(2.2)	(6.6)	--	--	(6.6)
Cash contributions from noncontrolling interests	--	--	4.9	4.9	--	--	4.9
Net cash proceeds from issuance of common units	--	--	--	--	29.0	--	29.0
Cash contributions from owners	31.8	17.3	(17.3)	31.8	--	(31.8)	--
Other financing activities	(84.6)	--	(0.1)	(84.7)	(9.7)	--	(94.4)
Cash provided by (used in) financing activities	(478.3)	(204.6)	193.3	(489.6)	(511.1)	499.8	(500.9)
Net change in cash and cash equivalents	52.6	10.5	5.7	68.8	--	(0.3)	68.5
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, March 31	$ 62.3	$ 31.8	$ (5.5)	$ 88.6	$ --	$ (0.3)	$ 88.3

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 423.9	$ 487.6	$ (473.7)	$ 437.8	$ 420.7	$ (424.0)	$ 434.5
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	27.8	213.6	(0.3)	241.1	--	--	241.1
Equity in income of unconsolidated affiliates	(458.0)	(31.8)	473.6	(16.2)	(424.0)	424.0	(16.2)
Distributions received from unconsolidated affiliates	65.5	56.1	(79.1)	42.5	481.7	(481.7)	42.5
Net effect of changes in operating accounts and other operating activities	455.1	(275.3)	(85.3)	94.5	6.3	--	100.8
Net cash flows provided by operating activities	514.3	450.2	(164.8)	799.7	484.7	(481.7)	802.7
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(24.9)	(685.4)	--	(710.3)	--	--	(710.3)
Other investing activities	(309.5)	79.0	214.4	(16.1)	(22.1)	22.1	(16.1)
Cash used in investing activities	(334.4)	(606.4)	214.4	(726.4)	(22.1)	22.1	(726.4)
Financing activities:							
Borrowings under debt agreements	2,662.1	159.5	--	2,821.6	--	--	2,821.6
Repayments of debt	(2,266.0)	(50.0)	--	(2,316.0)	--	--	(2,316.0)
Cash distributions paid to partners	(481.7)	(132.8)	132.8	(481.7)	(479.7)	481.7	(479.7)

Cash distributions paid to noncontrolling interests	--	(41.7)	24.5	(17.2)	--	--	(17.2)
Cash contributions from noncontrolling interests	--	214.3	(213.0)	1.3	--	--	1.3
Net cash proceeds from issuance of common units	--	--	--	--	21.0	--	21.0
Cash contributions from owners	22.1	1.4	(1.4)	22.1	--	(22.1)	--
Other financing activities	(18.5)	--	--	(18.5)	(3.9)	--	(22.4)
Cash provided by (used in) financing activities	(82.0)	150.7	(57.1)	11.6	(462.6)	459.6	8.6
Net change in cash and cash equivalents	97.9	(5.5)	(7.5)	84.9	--	--	84.9
Cash and cash equivalents, January 1	0.5	67.9	(2.9)	65.5	--	--	65.5
Cash and cash equivalents, March 31	$ 98.4	$ 62.4	$ (10.4)	$ 150.4	$ --	$ --	$ 150.4

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

For the three months ended March 31, 2012 and 2011.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying Notes included in this quarterly report on Form 10-Q and the Audited Consolidated Financial Statements and related Notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2011, as filed on February 29, 2012 (the “2011 Form 10-K”). Our financial statements have been prepared in accordance with generally accepted accounting principles (“GAAP”) in the United States (“U.S.”).

Key References Used in this Quarterly Report

Unless the context requires otherwise, references to “we,” “us,” “our,” “Enterprise” or “Enterprise Products Partners” intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC (“Enterprise GP”), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees (“DD LLC Trustees”) of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees (“EPCO Trustees”) of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer (“CEO”) of EPCO. Each of the EPCO Trustees is also a director of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC (“Duncan MergerCo,” a Delaware limited liability company and our wholly owned subsidiary), Duncan Energy Partners L.P. (“Duncan Energy Partners”) and DEP Holdings, LLC (“DEP GP,” the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the “Duncan Merger Agreement”). On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the “Duncan Merger”). Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements. For additional information regarding the Duncan Merger, see Note 1 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

References to “TEPPCO” mean TEPPCO Partners, L.P. prior to its merger with one of our subsidiaries on October 26, 2009.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries.

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As generally used in the energy industry and in this quarterly report, the acronyms below have the following meanings:

/d	= per day	MMBbls	= million barrels
BBtus	= billion British thermal units	MMBPD	= million barrels per day
Bcf	= billion cubic feet	MMBtus	= million British thermal units
BPD	= barrels per day	MMcf	= million cubic feet
MBPD	= thousand barrels per day	TBtus	= trillion British thermal units

Cautionary Statement Regarding Forward-Looking Information

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as “anticipate,” “project,” “expect,” “plan,” “seek,” “goal,” “estimate,” “forecast,” “intend,” “co “would,” “will,” “believe,” “may,” “potential” and similar expressions and statements regarding our plans and objectives future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A “Risk Factors” included in our 2011 Form 10-K. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” We were formed in April 1998 to own and operate certain natural gas liquids (“NGLs”) related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,600 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, crude oil, refined products and certain petrochemicals; and 14 Bcf of working natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. For information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP owns a non-economic general partner interest in us.

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Significant Recent Developments

The following information highlights significant developments since January 1, 2012 through the date of this filing (May 10, 2012), including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operation; and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations.

Plans to Construct Front Range Pipeline

In April 2012, we, along with Anadarko Petroleum Corporation and DCP Midstream, LLC formed a new joint venture, Front Range Pipeline LLC, to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend approximately 435 miles to Skellytown in Carson County, Texas. Each party holds a one-third ownership interest in the joint venture. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, is expected to provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. Depending on shipper interest in a binding open commitment period that commenced in April 2012, initial capacity on the Front Range Pipeline is expected to be approximately 150 MBPD, which can be readily expanded to approximately 230 MBPD. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

Expansion of Seaway Crude Oil Pipeline

We and Enbridge Inc. ("Enbridge") are nearing completion of the first phase of the reversal of the Seaway Crude Pipeline System (the "Seaway Pipeline"), which will provide 150 MBPD of southbound takeaway capacity from the Cushing, Oklahoma hub to the Gulf Coast as early as May 17, 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, throughput capacity on the Seaway Pipeline would increase to 400 MBPD, assuming a mix of light and heavy grades of crude oil.

In March 2012, we and Enbridge announced that we had secured capacity commitments from shippers to proceed with an expansion of the Seaway Pipeline. During the supplemental binding open commitment period, additional commitments were made with terms ranging from five to 20 years that support construction of a 512-mile, 30-inch diameter parallel pipeline along the existing route of the Seaway Pipeline, which would add 450 MBPD of throughput capacity to the system and bring total southbound throughput capacity up to 850 MBPD by mid-2014.

The reversed Seaway Pipeline will deliver crude oil from Cushing into the Houston, Texas market by utilizing affiliate and third party pipelines. Seaway plans to build a 65-mile pipeline that will link its pipeline to our Enterprise Crude Houston ("ECHO") crude oil storage terminal, which is being constructed southeast of Houston. Completion of this pipeline segment is expected in 2013. In addition, Seaway plans to build an 85-mile pipeline from our ECHO facility to the Port Arthur/Beaumont, Texas refining center that would provide shippers access to the region's heavy oil refining capabilities. Completion of this pipeline segment is expected in early 2014.

Plans to Construct NGL Fractionators Seven and Eight at Our Mont Belvieu Complex

In March 2012, we announced plans to construct two additional NGL fractionators at our Mont Belvieu, Texas complex that would provide us with 150 MBPD of incremental NGL fractionation capacity. The two new fractionation units (each with 75 MBPD of design capacity) are projected to begin service in the fourth quarter of 2013 and would facilitate the continued growth of NGL production from expanding production basins such as the Eagle Ford Shale in South Texas and various Rocky Mountain production basins. Once these two new units are constructed and placed in service, the NGL fractionation capacity of our Mont Belvieu units (eight fractionators in total) would be 610 MBPD in the aggregate.

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Development of Our ATEX Express Long-Haul Ethane Pipeline

In January 2012, we announced the receipt of sufficient transportation commitments to support development of our 1,230-mile Appalachia to Texas pipeline (the "ATEX Express") that will transport growing ethane production from the Marcellus and Utica Shale producing areas of Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. Demand for ethane feedstock over more expensive crude oil-based derivatives within the Gulf Coast petrochemical market has reached over 1 MMBPD and continues to increase given current pricing differentials. Several petrochemical companies have made announcements to modify, expand or build new facilities that would use ethane as a feedstock. As currently designed, the ATEX Express will have the capacity to transport up to 190 MBPD of ethane from the Appalachian production areas to our storage and distribution assets in southeast Texas.

The project would utilize a combination of new and existing infrastructure. The northern portion of the ATEX Express involves construction of a pipeline that would originate in Pennsylvania and extend west, then southwest, to Indiana following existing pipeline corridors in order to minimize the footprint of the project. The southern portion of ATEX Express would utilize a significant portion of our existing Products Pipeline System, which would be reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. At the southern terminus of the ATEX Express in Beaumont, we plan to construct a 55-mile pipeline to provide shippers with access to our NGL storage complex at Mont Belvieu, which would provide them with direct and indirect access to every ethylene plant in the U.S. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

Plans to Construct a Crude Oil Pipeline in the Gulf of Mexico with Genesis

In January 2012, we announced the execution of crude oil transportation agreements with a consortium of six Gulf of Mexico producers that will provide the necessary support for construction of a crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), which is a 50/50 joint venture owned by us and Genesis Energy, L.P. ("Genesis"). We will serve as construction manager and operator of the new deepwater pipeline (the "SEKCO Oil Pipeline"). The SEKCO Oil Pipeline is expected to begin service by mid-2014.

Sales of Energy Transfer Equity Common Units

At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of approximately $825.1 million and a gain on the sale of $27.5 million. Following the January 18 transaction, we sold an additional 3,569,232 Energy Transfer Equity common units through March 31, which generated cash proceeds of approximately $150.8 million and aggregate gains on these sales of $25.8 million. Proceeds from these sales were used for general company purposes, including funding capital expenditures.

Following completion of the January 18 transaction, our ownership percentage in Energy Transfer Equity was below 3% and we discontinued using the equity method to account for this investment and began accounting for the remaining units as an investment in available-for-sale equity securities. At March 31, 2012, we owned 2,971,646 common units of Energy Transfer Equity, which represented approximately 1.3% of its common units outstanding on April 3, 2012. We sold the remainder of our investment in Energy Transfer Equity in April 2012. See Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for information regarding our investment in Energy Transfer Equity and related sales.

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Results of Operations

The following table summarizes the key components of our results of operations for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2012	2011
Revenues	$11,252.5	$10,183.7
Operating costs and expenses	10,467.2	9,537.1
General and administrative costs	46.3	37.9
Equity in income of unconsolidated affiliates	9.9	16.2
Operating income	748.9	624.9
Interest expense	186.5	183.8
Benefit from (provision for) income taxes	34.4	(7.1)
Net income	655.5	434.5
Net income attributable to noncontrolling interests	4.2	13.8
Net income attributable to limited partners	651.3	420.7

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

Our non-GAAP gross operating margin by business segment and in total is as follows for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2012	2011
NGL Pipelines & Services	$654.9	$504.4
Onshore Natural Gas Pipelines & Services	206.2	159.2
Onshore Crude Oil Pipelines & Services	39.3	31.8
Offshore Pipelines & Services	52.1	61.3
Petrochemical & Refined Products Services	97.8	112.4
Other Investments (1)	2.4	6.3
Total segment gross operating margin	$1,052.7	$875.4

(1) Represents the equity earnings we recorded from our investment in Energy Transfer Equity. Our reporting for this segment ceased on January 18, 2012 when we stopped using the equity method to account for this investment. See Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our investment in Energy Transfer Equity.

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The following table presents a reconciliation of total segment gross operating margin to GAAP operating income and further to income before income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended March 31, 2012	2011
Total segment gross operating margin	$1,052.7	$875.4
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(254.6)	(230.8)
Non-cash asset impairment charges	(5.4)	--
Operating lease expenses paid by EPCO	--	(0.2)
Gains from asset sales and related transactions in operating costs and expenses	2.5	18.4
General and administrative costs	(46.3)	(37.9)
Operating income	748.9	624.9
Other expense, net	(127.8)	(183.3)
Income before income taxes	$621.1	$441.6

The following table summarizes each business segment's contribution to revenues (net of eliminations and adjustments) for the periods presented (dollars in millions):

	For the Three Months Ended March 31, 2012	2011
NGL Pipelines & Services:		
Sales of NGLs and related products	$4,115.3	$4,057.7
Midstream services	239.2	199.1
Total	4,354.5	4,256.8
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	572.6	712.7
Midstream services	261.0	203.9
Total	833.6	916.6
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,447.6	3,348.2
Midstream services	26.0	22.4
Total	4,473.6	3,370.6
Offshore Pipelines & Services:		
Sales of natural gas	0.1	0.3
Sales of crude oil	1.4	3.3
Midstream services	54.6	60.8
Total	56.1	64.4
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,351.2	1,382.8
Midstream services	183.5	192.5
Total	1,534.7	1,575.3
Total consolidated revenues	$11,252.5	$10,183.7

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Selected Price and Volumetric Data

The following table presents selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	Crude Oil, $/barrel (4)
2011									
1st Quarter	$ 4.11	$ 0.66	$ 1.37	$ 1.75	$ 1.85	$ 2.27	$ 0.76	$ 0.68	$ 94.10
2nd Quarter	$ 4.32	$ 0.78	$ 1.49	$ 1.87	$ 2.02	$ 2.48	$ 0.89	$ 0.79	$ 102.56
3rd Quarter	$ 4.20	$ 0.78	$ 1.54	$ 1.88	$ 2.09	$ 2.37	$ 0.78	$ 0.67	$ 89.76
4th Quarter	$ 3.54	$ 0.86	$ 1.44	$ 1.89	$ 2.26	$ 2.24	$ 0.59	$ 0.44	$ 94.06
2011 Averages	$ 4.04	$ 0.77	$ 1.46	$ 1.85	$ 2.06	$ 2.34	$ 0.76	$ 0.64	$ 95.12
2012									
1st Quarter	$ 2.72	$ 0.56	$ 1.26	$ 1.93	$ 2.04	$ 2.39	$ 0.69	$ 0.60	$ 102.93

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. (“CMAI”). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the New York Mercantile Exchange (“NYMEX”).

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The following table presents our significant average throughput, production and processing volumetric data for the periods presented. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for recently purchased assets from the date of acquisition.

	For the Three Months Ended March 31,	
	2012	2011
NGL Pipelines & Services, net:		
NGL transportation volumes (MBPD)	2,340	2,366
NGL fractionation volumes (MBPD)	623	549
Equity NGL production (MBPD) (1)	112	119
Fee-based natural gas processing (MMcf/d) (2)	4,134	3,698
Onshore Natural Gas Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	13,081	11,678
Onshore Crude Oil Pipelines & Services, net:		
Crude oil transportation volumes (MBPD)	706	666
Offshore Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	962	1,155
Crude oil transportation volumes (MBPD)	288	299
Platform natural gas processing (MMcf/d)	356	445
Platform crude oil processing (MBPD)	21	16
Petrochemical & Refined Products Services, net:		
Butane isomerization volumes (MBPD)	82	88
Propylene fractionation volumes (MBPD)	72	73
Octane additive and associated plant production volumes (MBPD)	4	13
Transportation volumes, primarily refined products and petrochemicals (MBPD)	659	743
Total, net:		
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	3,993	4,074
Natural gas transportation volumes (BBtus/d)	14,043	12,833
Equivalent transportation volumes (MBPD) (3)	7,689	7,451

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.
(2) Volumes reported correspond to the revenue streams earned by our gas plants.
(3) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Three Months Ended March 31, 2012 with Three Months Ended March 31, 2011

Revenues for the first quarter of 2012 were $11.25 billion compared to $10.18 billion for the first quarter of 2011, a $1.07 billion quarter-to-quarter increase primarily due to a $1.10 billion increase in crude oil sales revenues attributable to higher sales volumes and prices (more than 80% of the increase in crude oil sales revenues is due to higher sales volumes). Operating costs and expenses were $10.47 billion for the first quarter of 2012 compared to $9.54 billion for the first quarter of 2011, a $930.1 million quarter-to-quarter increase. Cost of sales related to our marketing activities increased $758.4 million quarter-to-quarter primarily due to higher crude oil sales volumes and prices.

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.35 per gallon during the first quarter of 2012 versus $1.36 per gallon during the first quarter of 2011. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $2.72 per MMBtu during the first quarter of 2012 versus $4.11 per MMBtu during the first quarter of 2011 – a 34% quarter-to-quarter decrease. The market price of crude oil (as measured on the NYMEX) averaged $102.93 per barrel during the first quarter of 2012 compared to $94.10 per barrel during the first quarter of 2011 – a 9% quarter-to-quarter increase. See "Selected Price and Volumetric Data" included within this Item 2 for additional historical energy commodity pricing information.

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General and administrative costs were $46.3 million for the first quarter of 2012 compared to $37.9 million for the first quarter of 2011. The $8.4 million quarter-to-quarter increase is primarily due to higher employee compensation, professional services and depreciation expenses for the first quarter of 2012 compared to the first quarter of 2011.

Consolidated interest expense was $186.5 million in the first quarter of 2012 compared to $183.8 million in the first quarter of 2011, a $2.7 million quarter-to-quarter increase. Although our average debt principal balances increased to $14.5 billion in the first quarter of 2012 from $14.11 billion in the first quarter of 2011, a substantial portion of the costs associated with the new borrowings was capitalized in connection with our capital spending program. Capitalized interest increased $13.4 million quarter-to-quarter to $30.6 million for the first quarter of 2012 from $17.2 million for the first quarter of 2011.

We recognized $53.3 million of gains during the first quarter of 2012 in connection with our sales of 26,331,868 common units of Energy Transfer Equity. These gains are a component of "Other, net" as presented on our Unaudited Condensed Statements of Consolidated Operations. See Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for information regarding our investment in Energy Transfer Equity and related sales.

We recognized a net income tax benefit of $34.4 million during the first quarter of 2012 compared to a $7.1 million provision for income taxes recognized for the first quarter of 2011. The $41.5 million quarter-to-quarter change in income taxes is primarily due to a $46.5 million benefit related to the conversion of certain of our subsidiaries to limited liability companies in the first quarter of 2012.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment and the primary drivers of these variances:

NGL Pipelines & Services. Gross operating margin from this business segment was $654.9 million for the first quarter of 2012 compared to $504.4 million for the first quarter of 2011, a $150.5 million quarter-to-quarter increase. Gross operating margin from our natural gas processing and related NGL marketing business was $421.7 million for the first quarter of 2012 compared to $277.7 million for the first quarter of 2011, a $144.0 million quarter-to-quarter increase. Gross operating margin from our NGL marketing activities increased $64.8 million quarter-to-quarter due to higher sales margins. Collectively, gross operating margin from our natural gas processing plants located in southern Louisiana, the Rocky Mountains and Permian Basin increased $72.2 million quarter-to-quarter primarily due to higher natural gas processing margins during the first quarter of 2012 compared to the first quarter of 2011 and a benefit of $20.0 million from a vendor settlement in the first quarter of 2012.

Gross operating margin from our NGL pipelines and related storage business was $168.4 million for the first quarter of 2012 compared to $179.9 million for the first quarter of 2011, an $11.5 million quarter-to-quarter decrease. Gross operating margin from our Dixie Pipeline and related NGL terminals decreased $8.5 million quarter-to-quarter primarily due to higher pipeline integrity expenses during the first quarter of 2012 and a 52 MBPD decrease in transportation volumes attributable to warmer weather and project-related downtime. Gross operating margin from our NGL pipelines in southern Louisiana decreased $7.3 million quarter-to-quarter primarily due to a 107 MBPD decrease in transportation volumes attributable to lower production volumes from the Gulf of Mexico and decreased volumes transported from Mont Belvieu to NGL fractionators in southern Louisiana. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $14.1 million quarter-to-quarter primarily due to an 84 MBPD increase in transportation volumes and an increase in system-wide tariffs in July 2011. Collectively, gross operating margin from the remainder of our NGL pipelines and related storage business decreased $9.8 million primarily due to higher operating expenses during the first quarter of 2012 compared to the first quarter of 2011. Gross operating margin from net operational measurement gains during the first quarter of 2011 that did not reoccur during the first quarter of 2012, higher maintenance expenses and expense accruals for sales and use taxes all contributed to the quarter-to-quarter increase in operating expenses.

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Gross operating margin from our NGL fractionation business was $64.8 million for the first quarter of 2012 compared to $46.8 million for the first quarter of 2011, an $18.0 million quarter-to-quarter increase. Gross operating margin from our Mont Belvieu NGL fractionators increased $14.0 million quarter-to-quarter primarily due to higher NGL fractionation volumes. During the fourth quarter of 2011, we placed into service a fifth NGL fractionator at our complex in Mont Belvieu, Texas, which added more than 75 MBPD of NGL fractionation capacity at this key industry hub.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $206.2 million for the first quarter of 2012 compared to $159.2 million for the first quarter of 2011, a $47.0 million quarter-to-quarter increase. Gross operating margin from our Acadian Gas System increased $40.8 million quarter-to-quarter primarily due to revenues earned by our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.18 TBtus/d of natural gas during the first quarter of 2012. Gross operating margin from our Texas Intrastate System increased $29.0 million quarter-to-quarter primarily due to higher firm capacity reservation revenues and a 428 BBtus/d quarter-to-quarter increase in natural gas throughput volumes. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during the first quarter of 2012 compared to the first quarter of 2011. Gross operating margin from our natural gas marketing activities decreased $5.8 million quarter-to-quarter primarily due to lower sales margins. Gross operating margin from our natural gas storage business was $1.8 million for the first quarter of 2012 compared to $13.2 million for the first quarter of 2011, an $11.4 million quarter-to-quarter decrease primarily due to the sale of our Mississippi natural gas storage facilities in December 2011.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $39.3 million for the first quarter of 2012 compared to $31.8 million for the first quarter of 2011, a $7.5 million quarter-to-quarter increase. Gross operating margin from our crude oil marketing and related activities increased $2.8 million quarter-to-quarter primarily due to higher sales volumes. Our crude oil marketing activities benefited from increased crude oil production volumes from supply basins in the Eagle Ford Shale, Barnett Shale, West Texas and Rocky Mountains. Collectively, gross operating margin from our South Texas Crude Oil Pipeline System, West Texas System, Red River System and Basin Pipeline System increased $5.8 million quarter-to-quarter due to a 41 MBPD increase in throughput volumes and higher average fees during the first quarter of 2012.

Offshore Pipelines & Services. Gross operating margin from this business segment was $52.1 million for the first quarter of 2012 compared to $61.3 million for the first quarter of 2011, a $9.2 million quarter-to-quarter decrease. Collectively, gross operating margin from our Independence Hub platform and Trail pipeline decreased $8.8 million quarter-to-quarter primarily due to lower throughput volumes and platform demand fee revenues during the first quarter of 2012 compared to the first quarter of 2011. Producers connected to our Independence Hub platform paid us approximately $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. Expiration of the contractual demand fees during the first quarter of 2012 resulted in a $4.0 million quarter-to-quarter decrease in gross operating margin. Net to our interest, natural gas processing volumes on the Independence Hub platform decreased 95 MMcf/d quarter-to-quarter as a result of depletion at existing production wells and the watering-out of certain wells, which volumes have not been replaced by new production.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $97.8 million for the first quarter of 2012 compared to $112.4 million for the first quarter of 2011, a $14.6 million quarter-to-quarter decrease.

Gross operating margin from propylene fractionation and related activities was $61.1 million for the first quarter of 2012 compared to $48.8 million for the first quarter of 2011, a $12.3 million quarter-to-quarter increase. The quarter-to-quarter increase in gross operating margin is primarily due to higher propylene sales volumes and margins during the first quarter of 2012 compared to the first quarter of 2011.

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Gross operating margin from butane isomerization was $20.6 million for the first quarter of 2012 compared to $25.7 million for the first quarter of 2011, a $5.1 million quarter-to-quarter decrease. The quarter-to-quarter decrease in gross operating margin is primarily due to lower isomerization volumes and decreased by-product sales. The decrease in isomerization volumes was attributable to downtime at our octane enhancement facility during the first quarter of 2012, which reduced the demand for isobutane used as feedstock.

Gross operating margin from octane enhancement and HPIB production was a loss of $13.1 million for the first quarter of 2012 compared to income of $6.1 million for the first quarter of 2011, a $19.2 million quarter-to-quarter decrease. The quarter-to-quarter decrease in gross operating margin is primarily due to lower volumes and higher operating expenses at our octane enhancement facility in Mont Belvieu, Texas as a result of unscheduled maintenance during the first quarter of 2012.

Gross operating margin from refined products pipelines and related activities was $12.1 million for the first quarter of 2012 compared to $18.3 million for the first quarter of 2011, a $6.2 million quarter-to-quarter decrease. The quarter-to-quarter decrease in gross operating margin is primarily due to a 59 MBPD quarter-to-quarter decrease in propane and butane volumes delivered to Northeast U.S. markets and a 59 MBPD quarter-to-quarter decrease in refined products volumes delivered to Midwest U.S. markets. Warmer weather during the first quarter of 2012 compared to the same period in 2011 resulted in lower demand for propane used as heating fuel, while shipments of refined products from the Gulf Coast to Midwest markets decreased as a result of low prices for such products.

Liquidity and Capital Resources

At March 31, 2012, we had $3.59 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO’s $3.5 Billion Multi-Year Revolving Credit Facility. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

Long-Term Debt

We had approximately $14.58 billion of principal amounts outstanding under consolidated debt agreements at March 31, 2012. In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE. These notes were issued at 99.542% of their principal amount, have a fixed-rate of interest of 4.85% and mature on August 15, 2042. Net proceeds from the issuance of Senior Notes EE were used to temporarily reduce borrowings outstanding under EPO’s $3.5 Billion Multi-Year Revolving Credit Facility (which was used to repay at maturity its $490.5 million principal amount of Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 prior to the delivery of Senior Notes EE) and for general company purposes.

For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Registration Statements

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have filed a universal shelf registration statement (the “2010 Shelf”) with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO utilized the 2010 Shelf to issue its Senior Notes EE in February 2012.

In March 2012, we filed a registration statement with the SEC authorizing the issuance of up to $1.0 billion in our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of March 31, 2012, we have not issued any common units under this registration statement.

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For information regarding our registration statements, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings

As of May 1, 2012, the investment-grade credit ratings of EPO's senior unsecured debt securities were: BBB from Standard and Poor's; Baa2 from Moody's; and BBB from Fitch Ratings. EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

	For the Three Months Ended March 31,	
	2012	2011
Net cash flows provided by operating activities	$604.9	$802.7
Cash used in investing activities	35.5	726.4
Cash provided by (used in) financing activities	(500.9)	8.6

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Part I, Item 1A of our 2011 Form 10-K.

The following information highlights significant quarter-to-quarter variances in our cash flow amounts and the primary drivers of these variances:

Comparison of Three Months Ended March 31, 2012 with Three Months Ended March 31, 2011

Operating Activities. The $197.8 million quarter-to-quarter decrease in net cash flows provided by operating activities was primarily due to the timing of related cash receipts and disbursements partially offset by increased earnings (e.g., our gross operating margin increased $177.3 million quarter-to-quarter).

Investing Activities. The $690.9 million decrease in cash used for investing activities was primarily due to proceeds from asset sales, which increased $914.0 million quarter-to-quarter due to the sale of 26,331,868 Energy Transfer Equity common units for $975.9 million during the first quarter of 2012 partially offset by a $257.8 million increase in capital spending for property, plant and equipment primarily for Eagle Ford Shale growth capital projects.

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Financing Activities. Cash used in financing activities was $500.9 million during the first quarter of 2012 compared to cash provided by financing activities of $8.6 million during the first quarter of 2011. The $509.5 million change was primarily due to the following:

§ Net borrowings under our consolidated debt agreements decreased $409.0 million quarter-to-quarter. EPO issued $750.0 million and repaid $500.0 million in principal amount of senior notes during the first quarter of 2012, compared to the issuance of $1.5 billion and repayment of $450.0 million in principal amount of senior notes during the first quarter of 2011. In addition, net repayments under our consolidated revolving bank credit facilities and term loans decreased approximately $388.5 million quarter-to-quarter.

§ Monetization of interest rate derivative instruments during the first quarter of 2012 resulted in a net cash outflow of $77.6 million compared to a $5.7 million outflow for similar activities during the first quarter of 2011. For information regarding our interest rate hedging activities, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

§ Cash distributions paid to limited partners increased $50.7 million quarter-to-quarter primarily due to a higher number of distribution-bearing common units outstanding and the associated quarterly distribution rates.

Capital Spending

An integral part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Barnett, Eagle Ford, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico producing regions.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2012	2011
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$968.1	$710.3
Capital spending for investments in unconsolidated affiliates	50.6	3.8
Other investing activities	--	3.6
Total capital spending	$1,018.7	$717.7

For the three months ended March 31, 2012, we spent $910 million on growth capital projects, of which approximately $449 million was for Eagle Ford Shale projects.

Based on information currently available, we estimate our consolidated capital spending for 2012 will approximate $4.0 billion, which includes estimated expenditures of $3.7 billion for growth capital projects and $0.3 billion for sustaining capital expenditures. Our forecast of consolidated capital expenditures for 2012 is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means,

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including borrowings under debt agreements, issuance of additional debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently intend to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At March 31, 2012, we had approximately $958.2 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas, including those in the Eagle Ford Shale and at our Mont Belvieu facility.

Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2012	2011
Expensed	$19.0	$7.7
Capitalized	12.9	10.7
Total	$31.9	$18.4

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $85.0 million for the remainder of 2012. The cost of our pipeline integrity program was $117.3 million for the year ended December 31, 2011.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2011 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional judgment and involve complex analysis:

§ depreciation methods and estimated useful lives of property, plant and equipment;
§ measuring recoverability of long-lived assets and equity method investments;
§ amortization methods and estimated useful lives of qualifying intangible assets;
§ methods we employ to measure the fair value of goodwill;
§ revenue recognition policies and the use of estimates when recording revenue and expense accruals;
§ reserves for environmental matters and litigation contingencies; and

- natural gas imbalances.

When used in the preparation of our Unaudited Condensed Consolidated Financial Statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Recent Accounting Developments

Accounting standard setting organizations have been very active in recent years. Recently, they issued new and revised accounting guidance on a number of topics, including balance sheet offsetting. We do not believe that adoption of this new guidance will have a material impact on our consolidated financial statements.

Other Items

Contractual Obligations

Since January 1, 2012, we (i) issued Senior Notes EE in February 2012 and (ii) repaid our Senior Notes S and $9.5 million principal amount of TEPPCO Senior Notes in February 2012. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for information regarding our consolidated debt obligations. There were no material changes in our operating lease or purchase obligations since those reported in our 2011 Form 10-K.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

Related Party Transactions

For information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Substantially all of our derivatives are used for non-trading activities.

Our exposures to market risk have not changed materially since those reported under Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2011 Form 10-K.

We assess the risk of each of our derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying interest rates or quoted market prices (as applicable) at the dates indicated. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. The calculated results of the sensitivity analysis model do not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. If changes in market conditions or exposures warrant, the nature and volume of derivative instruments may change depending on the specific exposures being managed.

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See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Derivative Instruments

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements. As presented in the tabular data below, each portfolio's estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates presented (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	March 31, 2012	April 17, 2012
FV assuming no change in underlying interest rates	Asset	$67.2	$16.8	$21.8
FV assuming 10% increase in underlying interest rates	Asset	64.4	15.0	20.1
FV assuming 10% decrease in underlying interest rates	Asset	70.0	18.8	23.5

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our forward starting swap portfolio at the dates presented (dollars in millions):

		Forward Starting Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	March 31, 2012	April 17, 2012
FV assuming no change in underlying interest rates	Liability	$(290.7)	$(146.5)	$(174.6)
FV assuming 10% increase in underlying interest rates	Liability	(251.8)	(115.4)	(145.6)
FV assuming 10% decrease in underlying interest rates	Liability	(330.6)	(178.5)	(204.4)

Due to a decrease in forward London Interbank Offered Rates in 2011, the fair value of our forward starting swap portfolio was a liability of $290.7 million at December 31, 2011. In connection with the issuance of Senior Notes EE in February 2012, we settled ten forward starting swaps having an aggregate notional value of $500.0 million, resulting in our making cash payments totaling $115.3 million. The fair value of the remaining forward starting swaps was a liability of $146.5 million at March 31, 2012 and $174.6 million at April 17, 2012. The $28.1 million increase in the liability between March 31 and April 17 is attributable to further decreases in forward London

Interbank Offered Rates during April.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and options contracts.

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Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory; and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as plant thermal reduction ("PTR") and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2012, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At March 31, 2012, the program had hedged future remaining estimated gross margins (before plant operating expenses) of $591.8 million on 12.2 MMBbls of forecasted NGL sales transactions and equivalent PTR volumes extending through December 2012. Our estimates of future gross margins are subject to various business risks, including unforeseen outages or declines, counterparty risk, or similar events or developments that are outside of our control.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2011	March 31, 2012	April 17, 2012
FV assuming no change in underlying commodity prices	Asset	$22.2	$26.6	$27.8
FV assuming 10% increase in underlying commodity prices	Asset	14.9	22.0	24.2
FV assuming 10% decrease in underlying commodity prices	Asset	29.5	31.3	31.5

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The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2011	March 31, 2012	April 17, 2012
FV assuming no change in underlying commodity prices	Liability	$(12.3)	$(50.2)	$(45.9)
FV assuming 10% increase in underlying commodity prices	Liability	(32.2)	(99.7)	(97.8)
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	7.6	(0.8)	6.0

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2011	March 31, 2012	April 17, 2012
FV assuming no change in underlying commodity prices	Liability	$(7.6)	$(5.9)	$(4.5)
FV assuming 10% increase in underlying commodity prices	Liability	(10.0)	(12.5)	(7.8)
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	(5.0)	0.7	(1.2)

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of our general partner's chief executive officer (Michael A. Creel, who is our principal executive officer) and chief financial officer (W. Randall Fowler, our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this quarterly report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the first quarter of 2012, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this quarterly report (see Exhibits 31 and 32 under Part II, Item 6 of this quarterly report).

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding litigation matters, see Note 14, "Commitments and Contingencies," of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which is incorporated herein by reference.

Item 1A. Risk Factors.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2011 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2011 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

The following table summarizes our repurchase activity during the first quarter of 2012:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2012 (1)	187,343	$51.55	--	--

(1) Of the 632,298 restricted common units that vested in February 2012 and converted to common units, 187,343 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).

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2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	

	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.6	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).

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3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.8	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.9	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.10	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.11	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.12	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).

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4.13	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.14	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.15	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.16	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.17	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.18	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.19	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.20	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.21	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.22	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.23	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.24	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.25#	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee.
4.26	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.27	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).

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4.28	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.29	Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.30	Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.33	Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.34	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.35	Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.36	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.37	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.38	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.39	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.40	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.41	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.42	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.43	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.44	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).

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4.47	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.48	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.49	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.50	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.51	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.52	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.53	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.54	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.55	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (included in Exhibit 4.25 above).
4.56	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.57	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.58	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.59	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.60	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.61	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.62	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).

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4.63	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.64	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.65	Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.66	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.67	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.68	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.69	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.70	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.71	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.72	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
4.73	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream

Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).

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4.74	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.75	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
12.1#	Computation of ratio of earnings to fixed charges for the three months ended March 31, 2012 and for each of the five years ended December 31, 2011, 2010, 2009, 2008 and 2007.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s for the March 31, 2012 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s for the March 31, 2012 quarterly report on Form 10-Q.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s for the March 31, 2012 quarterly report on Form 10-Q.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s for the March 31, 2012 quarterly report on Form 10-Q.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on May 10, 2012.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By:	Enterprise Products Holdings LLC, as General Partner
By:	/s/ Michael J. Knesek
Name:	Michael J. Knesek
Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner