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

Form 10-K

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

For the fiscal year ended December 31, 2013

or

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

For the transition period from______to______ .

Commission File Number 1-33825

El Paso Pipeline Partners, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**26-0789784**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

1001 Louisiana Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)
Registrant's telephone number, including area code: (713) 369-9000

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

Title of Each Class	Name of Each Exchange on which Registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☑ No ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☑ No ☐

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

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

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

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

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $5,558,190,957 on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the price of $43.67 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date. As of January 31, 2014, the registrant had 217,831,642 Common Units and 4,445,455 General Partner Units outstanding.

EL PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
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EL PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

Company Abbreviations

Bear Creek	=	Bear Creek Storage Company, L.L.C.	KMP	=	Kinder Morgan Energy Partners, L.P.
CIG	=	Colorado Interstate Gas Company, L.L.C.	Ruby	=	Ruby Pipeline Holdings Company, L.L.C.
CPG	=	Cheyenne Plains Gas Pipeline Company, L.L.C.	SLC	=	Southern Liquefaction Company, L.L.C.
Elba Express	=	Elba Express Company, L.L.C.	SLNG	=	Southern LNG Company, L.L.C.
ELC	=	Elba Liquefaction Company, L.L.C.	SNG	=	Southern Natural Gas Company, L.L.C.
El Paso	=	El Paso Holdco LLC	Totem	=	Totem Gas Storage Facility
EPNG	=	El Paso Natural Gas Company	TGP	=	Tennessee Gas Pipeline Company, L.L.C.
EPPOC	=	El Paso Pipeline Partners Operating Company, L.L.C.	WIC	=	Wyoming Interstate Company, L.L.C.
High Plains	=	High Plains Pipeline	WYCO	=	WYCO Development L.L.C.
KMI	=	Kinder Morgan, Inc.	Young	=	Young Gas Storage Company, Ltd.

Unless the context otherwise requires, references to "us," "we," "our," "ours," or "EPB," are describing El Paso Pipeline Partners, L.P. and/or our subsidiaries, as applicable.

Common Industry and Other Terms

AFUDC	=	allowance for funds used during construction	GAAP	=	U.S. Generally Accepted Accounting Principles
BBtu/d	=	billion British thermal units per day	IDR	=	incentive distribution right
Bcf	=	billion cubic feet	LIBOR	=	London Interbank Offered Rate
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act	LLC	=	Limited Liability Company
/d	=	per day	LNG	=	liquefied natural gas
DCF	=	distributable cash flow	MDth	=	thousand dekatherm
DD&A	=	depreciation and amortization	MLP	=	master limited partnership
DOE	=	U.S. Department of Energy	MMcf/d	=	million cubic feet per day
DOT	=	U.S. Department of Transportation	NYSE	=	New York Stock Exchange
Dth	=	dekatherm	OSHA	=	Federal Occupational Safety and Health Act
EBDA	=	Earnings before depreciation and amortization	PHMSA	=	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
FERC	=	Federal Energy Regulatory Commission	PRP	=	Potentially Responsible Party
FASB	=	Financial Accounting Standards Board	SEC	=	U.S. Securities and Exchange Commission
FTA	=	Free Trade Agreement			

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

Information Regarding Forward-Looking Statements

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

- the availability of drop-down assets and the terms and timing of sales from KMI;
- price trends and overall demand for natural gas in the U.S.;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates required by the FERC;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;
- our ability to safely operate and maintain our existing assets and to access or construct new pipeline, gas processing and LNG facilities;
- our ability to attract and retain key management and operations personnel;
- changes in natural gas production from exploration and production areas that we serve;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- our ability to obtain permits required for new construction projects and permit renewals for current operations in a timely manner;
- changes in accounting standards that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement the portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt and/or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, accidents, sabotage, cyber attacks, terrorism or other similar acts causing damage to our properties greater than our insurance coverage limits;
- possible changes in our credit ratings;

- capital and credit markets conditions, inflation and fluctuation in interest rates;
- global political and economic stability;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- the timing and extent of changes in natural gas commodity prices;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts; and
- unfavorable results of litigation and the outcome of contingencies referred to in Note 9 to our consolidated financial statements.

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

See Item 1A "Risk Factors" for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in Item 1A "Risk Factors." The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law and described below under Items 1 and 2, "Business and Properties—2014 Outlook," to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

PART I

Item 1 and 2. *Business and Properties.*

Overview

We are a Delaware MLP formed in 2007 to own and operate interstate natural gas transportation and terminaling facilities. Our common units, which represent limited partner interests in us, trade on the NYSE under the symbol “EPB.” We are controlled by our general partner, El Paso Pipeline, GP Company, L.L.C., an indirect wholly owned subsidiary of KMI. As of December 31, 2013, we own WIC, SLNG, Elba Express, SNG, CIG, SLC and CPG.

WIC and CIG are interstate pipeline systems serving the Rocky Mountain region. CPG is an interstate pipeline which serves the Rocky Mountain and Midwest regions. SLNG owns the Elba Island LNG storage and regasification terminal near Savannah, Georgia. Elba Express and SNG are interstate pipeline systems serving the southeastern region of the U.S. Our equity method investments include WYCO, which is owned 50% by CIG, Bear Creek, which is owned 50% by SNG, and ELC, which is owned 51% by SLC. ELC was formed in January 2013 to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal.

Our pipeline systems, storage facilities and LNG receiving terminal operate under tariffs approved by the FERC that establish rates, cost recovery mechanisms and other terms and conditions of services to our customers. The fees or rates established under our tariff are a function of our cost of providing services to our customers, including a reasonable return on our invested capital.

Financial Information

See Item 7 “Management's Discussion and Analysis of Financial Condition and Results of Operations” and Item 15 “Exhibits and Financial Statement Schedules” for financial information related to our operating results and financial condition. For financial information related to significant customers, see Note 12 to our consolidated financial statements.

Outlook for 2014

We expect to declare total cash distributions of $2.60 per unit for 2014, an approximate 2% increase over our 2013 distributions of $2.55 per unit. Our 2014 budget includes the expected purchase (drop-down transaction) from KMI of 50% interest in Ruby Pipeline, 50% interest in Gulf LNG and 47.5% interest in Young Gas Storage. The positive impact from the expected drop-down transaction at attractive multiples will be largely offset by the impacts of the SNG and WIC rate cases and expected lower rates on contract renewals on the WIC system. In 2014, we expect our regulated pipeline and storage assets, along with our LNG business, to generate earnings before DD&A of approximately $1.3 billion (adding back our share of joint venture DD&A), an increase of almost $90 million compared to 2013. We also have approximately $1.3 billion of expansion projects under contract with customers, which will benefit our unitholders in 2016 and beyond.

Our Outlook for 2014 is not a guarantee of performance. This Outlook involves risks, uncertainties and assumptions. Further, many of the factors that will determine these results are beyond our ability to control or predict. Because of these uncertainties, it is inadvisable to put undue reliance on any forward-looking statement. Please read Item 1A "Risk Factors" for more information. We plan to provide updates to our 2014 Outlook when we believe previously disclosed projections no longer have a reasonable basis.

Business Strategy

Our business strategy is to:

- Focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure of growing markets within North America;
- Increase utilization of our existing assets while controlling costs, operating safely and employing environmentally sound operating practices;
- Leverage economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow; and
- Maximize the benefits of our financial structure to create and return value to our unitholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A "Risk Factors," there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

We regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions and approval of the parties' respective boards of directors. While there are currently no unannounced purchase agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Our Assets

The table below and discussion that follows provides detail of our pipeline systems as of December 31, 2013:

	As of December 31, 2013					Average Throughput		
Transmission System	Ownership Interest	Miles of Pipeline	Design Capacity	Storage Capacity	Remaining Weighted Average Transportation Contract Life	2013	2012	2011
	(%)		(MMcf/d)	(Bcf)	(Years)		(BBtu/d)	
SNG(a)	100	6,900	3,940	64	7	2,491	2,684	2,463
CIG(b)(c)	100	4,300	4,635	37	7	2,200	2,159	2,128
WIC(d)	100	800	3,855	—	5	2,556	2,884	2,482
CPG	100	400	1,201	—	4	278	380	495
Elba Express(e)	100	200	1,275	—	24	181	—	—

(a) SNG's storage capacity includes approximately 30 Bcf of storage capacity associated with its 50% ownership interest in Bear Creek, a joint venture with TGP, our affiliate.
(b) Volumes reflected are 100% of the volumes transported on the CIG system.
(c) CIG's storage capacity includes 7 Bcf of storage capacity from Totem, which is owned by WYCO, CIG's 50% equity investee.
(d) WIC's throughput includes 190 BBtu/d, 221 BBtu/d and 179 BBtu/d transported by WIC on behalf of CIG and 18 BBtu/d, 22 BBtu/d and 25 BBtu/d transported by WIC on behalf of CPG for the years ended December 31, 2013, 2012 and 2011, respectively.
(e) Elba Express was placed in service in March 2010 and although all the design capacity was under contract, the average volumes transported during 2012 and 2011 were not material. The design capacity of 1,275 MMcf/d consisted of the South to North capacity of 1,000 MMcf/d and the North to South capacity of 275 MMcf/d. Each directional capacity is inclusive of a 55 MMcf/d undivided interest owned by SNG.

SNG

SNG is comprised of pipelines extending from natural gas supply basins in Texas, Louisiana, Mississippi and Alabama to market areas in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SNG owns pipeline facilities serving southeastern markets in Alabama, Georgia and South Carolina. SNG owns 100% of the Muldon storage facility and a 50% interest in Bear Creek. The storage facilities have a combined peak withdrawal capacity of 1.2 Bcf/d. The SNG system is also connected to SLNG's Elba Island LNG terminal.

CIG

CIG is comprised of pipelines that deliver natural gas from production areas in the Rocky Mountains and the Anadarko Basin directly to customers in Colorado, Wyoming and indirectly to the Midwest, Southwest, California and Pacific Northwest. CIG also owns interests in five storage facilities located in Colorado and Kansas and one natural gas processing plant located in Wyoming.

CIG owns a 50% interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). WYCO owns Totem and the 164-mile High Plains, both of which are in northeast Colorado and are operated by CIG under a long-term agreement with WYCO. Totem has a peak withdrawal capacity of 200 MMcf/d and a maximum injection rate of 150 MMcf/d. Totem services and interconnects with High Plains. WYCO also owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to PSCo's Fort St. Vrain's electric generation plant, which CIG does not operate, and a compressor station in Wyoming leased by WIC.

WIC

WIC is comprised of a mainline system that extends from western Wyoming to northeast Colorado (the Cheyenne Hub) and several lateral pipeline systems that extend from various interconnections along the WIC mainline into western Colorado, northeast Wyoming and eastern Utah. WIC owns interstate natural gas transportation systems providing takeaway capacity from the mature Overthrust, Piceance, Uinta, Powder River and Green River Basins.

CPG

CPG is a pipeline system that extends from Cheyenne Hub in Weld County, Colorado and extends southerly to a variety of delivery points in the vicinity of the Greensburg Hub in Kiowa County, Kansas. CPG provides pipeline takeaway capacity from the natural gas basins in the Central Rocky Mountain area to the major natural gas markets in the Mid-Continent region.

Elba Express

Elba Express owns the Elba Express pipeline which is capable of transporting natural gas supplies in a northerly direction from the Elba Island LNG terminal to markets in the southeastern and eastern U.S. or transporting natural gas in a southerly direction from interconnections with Transcontinental pipeline to markets located on Elba Express or to interconnections between Elba Express and SNG, Carolina Gas Transmission and SLNG. Under a firm transportation service agreement, the entire south to north capacity of Elba Express is contracted to Shell NA LNG LLC (Shell LNG) for 30 years at a fixed rate that was reduced on December 31, 2013 and will remain flat thereafter with respect to current facilities. The Shell LNG firm transportation service agreement is supported by a parent guarantee from Shell Oil Company (Shell) that secures the timely performance of the obligations of the agreement. Under a separate firm transportation service agreement, the entire north to south capacity of Elba Express is contracted to BG LNG Services, LLC (BG LNG) for 25 years at a fixed rate. The BG LNG firm transportation service agreement is supported by a parent guarantee from BG Energy Holdings Limited that secures the timely performance of the obligations of the agreement.

SLNG

The table below and discussion that follows provides detail of our LNG facilities as of December 31, 2013:

	As of December 31, 2013				Average Daily Sendout		
LNG Terminal	**Ownership Interest**	**Peak Vaporization Capacity**	**Storage Capacity**	**Remaining Weighted Average Contract Life**	**2013**	**2012**	**2011**
	(%)	**(MMcf/d)**	**(Bcf)**	**(Years)**		**(MMcf/d)**	
SLNG	100	1,755	11.5	19	45	174	192

SLNG owns the Elba Island LNG receiving terminal, located near Savannah, Georgia. The Elba Island LNG terminal is one of nine land-based terminal facilities in the U.S. capable of providing domestic storage and vaporization services to international producers of LNG. The capacity of the Elba Island LNG terminal is fully contracted with BG LNG Services, LLC (BG LNG) under a negotiated rate contract comprised predominately of a recourse based reservation rate with a small variable component and Shell LNG under a long-term step-down fixed reservation rate contract (that was reduced beginning on December 31, 2013 and will remain flat thereafter). The reservation rate payments due under these contracts are payable to us regardless of utilization. The firm SLNG service agreements are supported by parent guarantees from BG Energy Holdings Limited (BG) and Shell that secure the timely performance of the obligations of those agreements. The Elba Island LNG terminal is directly connected to three interstate pipelines, indirectly connected to two others, and also connected by commercial arrangements to a major local distribution company; thus, it is readily accessible to the southeast and mid-Atlantic markets.

Markets and Competition

Our customers include natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies. We provide transportation and storage services in both our natural gas supply and market areas, and in doing so, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear energy, wind, hydroelectric power, solar and fuel oil.

The U.S. natural gas industry has experienced a significant increase in production since the middle of the previous decade, as well as a major shift in the geographic location of supply sources. These changes have resulted primarily from the industry's success in commercializing horizontal drilling and hydraulic fracturing techniques for the production of gas from shale formations. Domestic oil production has also increased substantially, resulting in increased production of "associated gas" (natural gas produced as a byproduct from formations that produce primarily oil or liquids). These new supply sources continue to affect gas supply and flow patterns throughout North America, as well as the rates that pipeline systems can charge for their services. The impacts vary among pipeline systems and over time, as production from these new sources increases and pipelines compete to provide market access for these supplies, often displacing traditional supply sources. Our SNG system directly accesses the Haynesville Shale in northern Louisiana and indirectly accesses, through interconnecting pipelines, the Barnett Shale, Bossier Sands, Woodford Shale and Fayetteville Shale. Planned projects on interconnecting pipelines will allow our Elba Express system to access natural gas supplies from the Marcellus Shale, located primarily in Pennsylvania. Moreover, our gas pipelines serving the Rocky Mountain area are directly connected to the Niobrara Shale formation along the Front Range of the Rockies in Colorado and Wyoming.

Another change in the supply patterns is the reduction of gas imports from Canada and increased exports to Mexico. The decreases in imported supplies from Canada have been the result of declining conventional production and increasing demand in Canada as well as increased production from shale formations in the northeast U.S. On the southern border, exports to Mexico are increasing and may increase further over time as demand growth exceeds production growth in that country. In addition to these trends in Canada and Mexico, imports of LNG to the U.S. have been declining over the last several years in response to increased U.S. shale gas production which has resulted in a decline in U.S. natural gas prices relative to gas prices in Europe and Asia. The projected gas price disparity between U.S. and European/Asian markets suggests that North America could change from a net importer of LNG to a net exporter of LNG before the end of this decade.

Electric power generation has been the source of most of the demand growth for natural gas over the last 10 years, and this trend is expected to continue. The growth of natural gas in this sector is influenced by competition with coal and economic growth. Short-term market shifts have been driven by relative electricity generation costs of coal-fired plants versus gas-fired plants. A long-term market shift in the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources. Industrial demand has also grown recently with the economic recovery and the low natural gas price environment, and this sector offers an opportunity for continued growth. All of the aforementioned factors have led to increased demand for domestic supplies and related transportation services over the last several years.

For a further discussion of factors impacting our markets and competition, See Item 1A "Risk Factors."

SNG

The Southeastern market served by the SNG system is one of the fastest growing natural gas demand regions in the U.S. Demand for deliveries from the SNG system is characterized by two peak delivery periods, the winter heating season and the summer cooling season. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative delivery points. Natural gas delivered from the SNG system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal, fuel oil and nuclear. Some of SNG’s largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. In addition, SNG competes with third party pipelines and gathering systems for connection to new supply sources.

SNG’s most direct competitor is Transco, which owns pipelines extending from Texas to New York. It has firm transportation contracts with SNG’s largest customer, Atlanta Gas Light Company, a subsidiary of AGL Resources. Further, Spectra has announced plans to construct its Sabal Trail pipeline, which is being built primarily to serve markets in Florida, but in the future could directly compete with SNG for markets in South Georgia.

CIG

Our CIG system serves two major markets, an on-system market and an off-system market. The on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an interstate pipeline, local production from the Denver-Julesburg basin and long haul shippers who elect to sell into this market rather than the off-system. The off-system market consists of the transportation of Rocky Mountain natural gas production from multiple supply basins to interconnections with other pipelines in the Midwest, Southwest, California and the Pacific Northwest. Competition for our off-system market consists of other interstate pipelines, including WIC, that are directly connected to our supply sources. CIG also faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.

CIG also competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Some of CIG’s largest customers could obtain a significant portion of their natural gas requirements through transportation from other pipelines.

WIC

Our WIC system competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers. Its four largest customers generally have competitive transportation alternatives for significant portions of their natural gas transportation requirements. These competitor pipelines include the Rockies Express Pipeline LLC (Rockies Express), Bison Pipeline LLC (Bison) and CIG. Expiring contracts on the WIC Medicine Bow lateral were not renewed due to the decline in drilling in the Powder River Basin and the commissioning of Bison in early 2011. In addition, WIC competes with CIG, third party pipelines and gathering systems for connection to the supply sources in the U.S. Rocky Mountain region. Natural gas delivered from the WIC system competes with alternative energy sources used to generate electricity, such as hydroelectric power, solar, wind, coal and fuel oil.

CPG

CPG competes directly with other interstate pipelines serving the Mid-Continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets. CPG has high interconnectivity at the Cheyenne Hub. The Cheyenne Hub is connected directly or indirectly to all major pipelines within the Rockies, which gather from all major producing basins in the region. CPG's interconnects near Greensburg, Kansas continue to benefit customers in the Mid-continent by continuing to provide increased reliability (due to pipeline diversity), increased optionality (due to supply basin diversity), and advantageous pricing (due to gas-on-gas competition). CPG is positioned to accommodate the incremental production from associated gas within the high liquid content plays out of the Denver Basin.

Elba Express

Elba Express was originally designed to transport LNG supplies received by SLNG to markets in the southeast. However, the recent proliferation of gas production from shale formations has shifted the global LNG supply dynamics. With this shift, customers and potential customers of Elba Express have expressed a desire to displace supply from imported LNG with domestically produced natural gas for delivery to southeast markets and for LNG export. See Item 7 "Liquefaction Project" for further discussion regarding LNG exports. In 2013, Elba Express placed facilities in-service (Elba Express Phase B Expansion) to effectuate transporting gas from domestic sources to markets in the southeast for a subsidiary of the BG Group. In addition, during 2013 Elba Express held an open season for additional capacity from domestic supply sources. As a result of the open season, Elba Express will be seeking authorization from the FERC to further expand its system. These new facilities, which are anticipated to be in-service beginning in 2016, will further increase the capacity of Elba Express moving north to south and will be subscribed under long-term negotiated reservation-based contracts.

SLNG

SLNG's terminal capacity is completely subscribed under long-term contracts with subsidiaries of BG and Shell. Revenues from these contracts are predominantly based on reservation charges; therefore, changes in throughput at the terminal driven by domestic or global competition will have relatively little effect on our revenue stream or profitability. Since SLNG's Elba Island LNG terminal is directly connected to three interstate pipelines, and indirectly connected to two others, it is readily accessible to markets in southeast U.S. and the mid-Atlantic as well as supply from the newly developed shale formations. The recent proliferation of gas production from shale formations has shifted the desire of global LNG suppliers from importing LNG to the U.S. to seeking opportunities to export LNG from the U.S. SLNG is well positioned for the LNG export opportunity. See Item 7 "Liquefaction Project" for further discussion regarding SLNG's LNG export project. Several other competing LNG export projects have been proposed and are in various stages of development. LNG export demand is highly dependent on domestic natural gas pricing relative to pricing in European and Asian markets. As such, the total LNG export market is difficult to quantify as many factors influence prices in these markets.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves tariffs that establish rates, cost recovery mechanisms and other terms and conditions of service to our customers. The fees or rates established under our tariffs are a function of providing services to our customers, including a reasonable return on our invested capital. The FERC's authority also extends to:

- rates and charges for natural gas transportation, storage and related services;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipelines and certain affiliates;
- terms and conditions of services;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

Safety Regulation

We are subject to safety regulations imposed by the PHMSA, including those requiring us to develop and maintain integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as high consequence areas (HCA), where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with the integrity management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

The President signed into law new pipeline safety legislation in January 2012, The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which increased penalties for violations of safety laws and rules, among other matters, and may result in the imposition of more stringent regulations in the next few years. PHMSA is also currently considering changes to its regulations. PHMSA issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We are also subject to the requirements of the OSHA and other comparable federal and state agencies that address employee health and safety. In general, we believe current expenditures are addressing the OSHA requirements and protection of the health and safety of our employees. Based on new regulatory developments, we may increase expenditures in the future to comply with higher industry and regulatory safety standards; however, such increases in our expenditures cannot be accurately estimated at this time.

Other Regulation

Our interstate pipeline systems are also subject to other federal, state and local safety and environmental statutes and regulations of the DOT and the U.S. Department of the Interior. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements. For a further discussion of the potential impact of regulatory matters on us, see Item 1A "Risk Factors" and Item 7 "Management’s Discussion and Analysis of Financial Condition and Results of Operations."

Our Relationship with KMI

We primarily operate in the regulated natural gas transportation sector of the energy industry. Our parent, KMI owns our 2% general partner interest, all of our incentive distribution rights and a 41% limited partner interest in us.

KMI is the largest midstream and the third largest energy company in North America with a combined enterprise value of approximately $110 billion. KMI owns an interest in or operates approximately 80,000 miles of pipelines and 180 terminals. KMI's pipelines transport natural gas, gasoline, crude oil, condensate, CO_2 and other products, and its terminals store petroleum products, ethanol and chemicals and handle such products as coal, petroleum coke and steel. KMI also owns the general partner and approximately 10% of the limited partner interests of KMP, a publicly-traded MLP in North America.

As a substantial owner in us, KMI is motivated to promote and support the successful execution of our business strategies, including utilizing our partnership as a growth vehicle for its natural gas transportation, storage and other energy infrastructure businesses. Although we have the opportunity to make additional acquisitions directly from KMI in the future, KMI is under no obligation to make acquisition opportunities available to us. See Item 1A “Risk Factors” for additional information related to risks regarding KMI's ownership of our general partner.

Environmental Matters

A description of our environmental remediation activities is included in Note 9 to our consolidated financial statements.

Other

Employees

We do not have employees. Employees of KMI and its affiliates provide services to our general partner, us and our subsidiaries. We are managed and operated by the directors and officers of our general partner. Under an omnibus agreement with El Paso and other policies with KMI and its affiliates, we reimburse KMI and its affiliates without a profit component for the provision of various general and administrative services for our benefit and for direct expenses incurred by KMI or its affiliates on our behalf. A further discussion of our affiliate transactions is included in Note 8 to our consolidated financial statements.

Properties

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

Available Information

Our website is www.kindermorgan.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after the reports are filed with the SEC. Information about each of the Board members of our general partner, as well as each of our general partner's Board's standing committee charters, our Corporate Governance Guidelines and our Code of Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

Item 1A. *Risk Factors.*

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial position, results of operations or cash flows. There are also risks associated with being an owner of common units in a partnership that are different than being an owner of common stock in a corporation. Investors in our common units should be aware that the realization of any of those risks could result in a decline in the trading price of our common units, and they might lose all or part of their investment.

Risks Related to Our Business

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

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

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

The FERC may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC or our customers could file complaints challenging the tariff rates charged by our pipelines, and a successful complaint could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what the FERC allows us to recover in our rates, or to the extent that there is a lag before we can file and obtain rate increases, our operating results, cash flows and financial position can be negatively impacted.

Our existing rates may also be challenged by complaint. Under certain circumstances prescribed by applicable regulations, regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge. Further, the FERC may initiate investigations to determine whether some interstate natural gas pipelines have over-collected on rates charged to shippers. Any successful challenge could materially adversely affect our future earnings, cash flows and financial condition.

Energy commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to natural gas transmission and storage activities such as leaks, explosions and mechanical problems that could result in substantial financial losses. In addition, these risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution and impairment of operations, any of which could also result in substantial financial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. Incidents that cause an interruption of service, such as when unrelated third party construction damages a pipeline or a newly completed expansion experiences a weld failure, could negatively impact our revenues and earnings while the affected asset is temporarily out of service. In addition, losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

Increased regulatory requirements relating to the integrity of our pipelines may require us to incur significant capital and operating expense outlays for compliance.

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the DOT and pipeline companies in the areas of testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs are pipeline integrity testing and the repairs found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in High Consequence Areas can have a significant impact on testing and repairs costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

We may face competition from other pipelines and other forms of transportation into the areas we serve.

Any current or future pipeline system or other form of transportation that delivers natural gas into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. To the extent that an excess of supply into these areas is created and persists, our ability to re-contract for expiring transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We also could experience competition for the supply of natural gas from both existing and proposed pipeline systems. Several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us.

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

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

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

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

Our interstate natural gas pipelines have federal eminent domain authority. However, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

Our business, financial condition and operating results may be affected adversely by increased costs of capital or a reduction in the availability of credit.

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

In addition, due to our relationship with KMI, our credit ratings, and thus our ability to access the capital markets and the terms and pricing we receive therein, may be adversely affected by any impairment to KMI's financial condition or adverse changes in its credit ratings. Similarly, any reduction in our credit ratings could negatively impact the credit ratings of our subsidiaries, which could increase their cost of capital and negatively affect their business and operating results. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our debt instruments, as well as the market value of our common units.

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

As of December 31, 2013, we had $4.3 billion of consolidated debt. This level of debt could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes; (ii) limiting our ability to use operating cash flow in other areas of our business or to pay distributions because we must dedicate a substantial portion of these funds to make payments on our debt; (iii) placing us at a competitive disadvantage compared to competitors with less debt; and (iv) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond our control. If our operating results are not sufficient to service our indebtedness, or any future indebtedness that we incur, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to affect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 5 to our consolidated financial statements.

A breach of the covenants applicable to our debt and other financing obligations could affect our ability to borrow funds, could accelerate repayment of our debt and other financing obligations and those of our subsidiaries and reduce our cash available for distribution to our unitholders.

Our debt and other financing obligations contain restrictive covenants and require us to maintain certain financial ratios, including debt to earnings before interest, income taxes, depreciation and amortization (EBITDA) and EBITDA to interest expense in our note purchase agreements and contain cross default provisions. Volatility in the financial markets and a reduction in access to capital could cause these covenants to become more restrictive over time. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations.

Restrictions in our credit agreement and note purchase agreements could limit our ability to make distributions to our unitholders.

Our credit agreement and the note purchase agreement related to our issuance of senior unsecured notes contain covenants limiting our ability to make distributions to our unitholders and equity repurchases. Our ability to comply with any restrictions and covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If we are unable to comply with these restrictions and covenants, a significant portion of indebtedness outstanding under our credit agreement or the note purchase agreement may become immediately due and payable, and our lenders' commitment to make further loans to us under our credit agreement may terminate. We may not have, or be able to obtain, sufficient funds to make these accelerated payments. Our payment of principal and interest on any future indebtedness will reduce our cash available for distribution to our unitholders. Further, our credit agreement limits our ability to pay distributions to our unitholders during an event of default or if an event of default results from the distribution.

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

Although a substantial portion of our debt capital structure has fixed interest rates, our revolving credit agreement is variable rate debt, therefore changes in market conditions, including potential increases in the deficits of foreign, federal and state governments, could have a negative impact on interest rates that could cause our financing costs to increase. As of December 31, 2013, we had no borrowings outstanding on our revolving credit agreement. Should we have an outstanding balance and interest rates increase, the amount of cash required to service this debt would increase and our earnings could be adversely affected. For more information about our interest rate risk, see Item 7A “Quantitative and Qualitative Disclosures about Market Risk.”

Our senior unsecured notes are obligations of EPPOC and not guaranteed by any of its subsidiaries. As such, the notes are effectively junior to EPPOC's existing and future secured debt and to all debt and other liabilities of its subsidiaries.

The notes are EPPOC's unsecured obligations and rank equally in right of payment with all of its other existing and future unsubordinated debt. All of EPPOC's operating assets are in subsidiaries of EPPOC, and none of these subsidiaries guarantee EPPOC's obligations with respect to the notes. Creditors of EPPOC's subsidiaries have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or other bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to EPPOC in respect of its direct or indirect equity interests in such subsidiaries. Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of the notes. As of December 31, 2013, the notes were effectively subordinated to approximately $2.0 billion of outstanding indebtedness of EPPOC's subsidiaries. Furthermore, such subsidiaries are not prohibited under the indenture from incurring additional indebtedness.

In addition, because the notes and the guarantee of the notes by EPB are unsecured, holders of any secured indebtedness of EPPOC or EPB would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of the notes. Currently, neither EPPOC nor EPB have any secured indebtedness. Although the indenture governing the notes places some limitations on the ability of EPPOC to create liens securing debt, there are significant exceptions to these limitations, which allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If EPPOC or EPB incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, the assets of EPPOC or EPB would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on the notes. Consequently, any such secured indebtedness would effectively be senior to the notes and the guarantee of the notes by EPB, to the extent of the value of the collateral securing the secured indebtedness. In that event, the noteholders may not be able to recover all the principal or interest that is due under the notes.

We may not be able to generate sufficient cash to service all of our indebtedness, including the notes and our indebtedness under our revolving credit agreement, and we may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure the noteholders that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness. If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our indebtedness, including the notes. We cannot assure the noteholders that we would be able to take any of these actions, that these actions would be successful and would permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements, including our credit agreement and the indenture that will govern the notes. In the absence of such cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. The agreement governing our revolving credit facility contains restrictions on our ability to dispose of assets. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them, and any proceeds may not be adequate to meet any debt service obligations when due.

Our pipelines depend on certain key customers for a significant portion of their revenues and the loss of any of these key customers could result in a decline in our revenues. In addition, we are exposed to the credit risk of our counterparties and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of our counterparties failing to make payments to us, which may include payments not being received within the time required under our contracts. Our current largest exposures are associated with shippers under long-term transportation contracts on our pipeline systems. Our systems rely on a limited number of customers for a significant portion of our systems' revenues. For the year ended December 31, 2013, the four largest customers for each of WIC, CIG, SNG, SLNG, Elba Express and CPG accounted for approximately 81%, 66%, 62%, 100%, 100% and 74% of their respective operating revenues. The creditworthiness of our customers may be adversely impacted by negative effects in the economy, including low natural gas prices which can reduce liquidity and cash flows for some of our customers that produce natural gas. The loss of all or a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts, could have a material adverse effect on us. Our credit procedures and policies that are governed by the FERC may not be adequate to fully eliminate counterparty credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future counterparties fail to pay and/or perform, we could be adversely affected. For example, we may not be able to effectively remarket capacity during and after insolvency proceedings involving a customer. For additional information regarding our major customers, see Note 12 to our consolidated financial statements.

We depend on distributions from our subsidiaries to meet our needs.

We have no significant assets other than our ownership interests in our operating subsidiaries. We are dependent on the earnings and cash flows, dividends, loans or other distributions from our subsidiaries to generate the funds necessary to meet our obligations. There are no significant restrictions on EPPOC's or EPB's ability to access the net assets or cash flows related to their controlling interests in the operating companies either through dividend or loan. Applicable law and contractual restrictions (including restrictions in certain of our subsidiaries' credit agreements and the rights of certain creditors of our subsidiaries that would often be superior to our interests) may negatively impact our ability to obtain such distributions from our subsidiaries.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may increase cash distributions during periods when we experience reductions in net income for financial accounting purposes and may reduce cash distributions during periods when we experience increases in net income for financial accounting purposes.

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

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

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

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

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition, expansion or construction project will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under the CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act or analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could influence our business, financial position, results of operations and prospects. For example, if an accidental leak occurs at or from our pipelines or our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our level of earnings and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we have utilized operating, handling and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Note 9 to our consolidated financial statements.

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

Methane, a primary component of natural gas, and carbon dioxide, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of greenhouse gases. The Environmental Protection Agency regulates greenhouse gas emissions and requires the reporting of greenhouse gas emissions in the U.S. for emissions from specified large greenhouse gas emission sources, fractionated natural gas liquids and certain stationary sources.

Because our operations, including our compressor stations and natural gas processing plants emit various types of greenhouse gases, primarily methane and carbon dioxide, such regulation could increase our costs related to operating and maintaining our facilities and could require us to install new emission controls equipment at our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas transported on our natural gas pipelines.

The natural gas industry is increasingly relying on natural gas supplies from unconventional sources, such as shale, tight sands and coal bed methane. Natural gas extracted from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by natural gas exploration and production operators in the completion of certain natural gas wells. Recently, there have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas transported on our natural gas pipelines, several of which gather natural gas from areas in which the use of hydraulic fracturing is prevalent.

Terrorist attacks or “cyber security” events, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other assets might be specific targets of terrorist organizations or “cyber security” events. These potential targets might include our pipeline systems or operating systems and may affect our ability to operate or control our pipeline assets, our operations could be disrupted and/or customer information could be stolen. The occurrence of one of these events could cause a substantial decrease in revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation or litigation and or inaccurate information reported from our operations.

There is no assurance that adequate sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

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

Our pipelines depend on production of natural gas in the areas served by our pipelines. Without reserve additions, production will decline over time as reserves are depleted and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our gas plants and pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at a level that encourages producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as a decline in natural gas prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from natural gas producing areas. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of natural gas. Each of these factors impact our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

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

The implementation of new regulations or the modification of existing regulations affecting the natural gas industry could reduce demand for natural gas, increase our costs and may have a material adverse effect on our results of operations and financial condition. We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the demand for natural gas.

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

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

Hurricanes, earthquakes and other natural disasters could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines and other assets are located in areas that are susceptible to hurricanes, earthquakes and other natural disasters. These natural disasters could potentially damage or destroy our pipelines and other assets and disrupt the supply of the products we transport through our pipelines. Natural disasters can similarly affect the facilities of our customers. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected.

There are accounting principles that are unique to regulated interstate pipeline assets that could materially impact our recorded earnings.

Accounting policies for FERC regulated pipelines are in certain instances different from U.S. GAAP for nonregulated entities. For example, we are required to record certain regulatory assets on our balance sheet that would not be recorded for nonregulated entities. In determining whether to account for regulatory assets on each of our pipelines, we consider various factors including regulatory changes and the impact of competition to determine the probability of recovery of these assets. Currently, all of our pipeline systems have regulatory assets recorded on their balance sheets. If we determine that future recovery is no longer probable for any of our pipeline systems, then we could be required to write off the regulatory assets in the future. In addition, we capitalize a carrying cost or AFUDC on equity funds related to our construction of long-lived assets. Equity amounts capitalized are included as "Other, net" on our Consolidated Statements of Income. We periodically evaluate the applicability of accounting standards related to regulated operations, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to evaluate our assets for impairment and write-off the associated regulatory assets and our future earnings could be impacted.

Our business requires the retention and recruitment of a skilled workforce and the loss of such workforce could result in the failure to implement our business plans.

We are managed and operated by KMI and its affiliates. Such operations and management require the retention and recruitment of a skilled workforce including engineers, technical personnel and other professionals. KMI competes with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible, which have significant institutional knowledge that must be transferred to other employees. If KMI is unable to (a) retain their current employees, (b) successfully complete the knowledge transfer and/or (c) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

Risks Inherent in Our Structure and Relationship with KMI

Our ability to continue to acquire interests in interstate pipelines from KMI could be negatively impacted by various factors that would reduce our growth opportunities.

An important source of our growth in the past and potentially in the future is the purchase of interests in interstate pipelines from our parent and its subsidiaries. Our general partner is entitled to IDRs, which are currently at the maximum level. As owner of our general partner, KMI ultimately benefits from these IDRs. Our ability to purchase additional interests on an accretive basis to the limited partner unitholders may be negatively impacted by such IDRs unless KMI causes our general partner to reduce the level of the IDRs as provided for in the partnership agreement. In addition, as the owner of the general partner of the partnership, KMI could also be subject to claims associated with conflicts of interest and breach of fiduciary duties. Although the partnership agreements expressly define and limit the obligations of our general partner, if any conflicts of interest or breach of fiduciary duties are found, then our ability to purchase additional interests in interstate pipeline assets from KMI could be negatively impacted.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to make distributions to unitholders and otherwise conduct our business.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of its available cash to our unitholders of record and our general partner. Available cash is generally defined as all of our cash-on-hand as of the end of a fiscal quarter, adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to its reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to reimburse our general partner for all expenses it has incurred on our behalf;
- to provide funds for distributions to our unitholders and its general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

KMI controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including KMI, have conflicts of interest with us and limited fiduciary duties and they may favor their own interests, including their interest in KMP, to the detriment of our unitholders.

KMI owns and controls our general partner, and appoints all of the directors of our general partner. Some of our general partner's directors, and some of its executive officers, are directors or officers of KMI or its affiliates. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to KMI. Therefore, conflicts of interest may arise between KMI and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

Affiliates of our general partner, including KMI and its other subsidiaries, are not limited in their ability to compete with us and are not obligated to offer us the opportunity to pursue additional assets or businesses, which could limit our commercial activities or our ability to acquire additional assets or businesses.

Neither our partnership agreement nor the omnibus agreement among us, El Paso and others will prohibit affiliates of our general partner, including KMP, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, KMI and its affiliates may acquire, construct or dispose of additional transportation or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. KMI and KMP are established participants in the interstate pipeline and/or storage business, and each may have greater resources than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact us.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which the common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner or its board of directors, and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, will be chosen entirely by its owners and not by the unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at such annual meetings of stockholders. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Cost reimbursements to our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution.

Pursuant to an omnibus agreement and other policies we have with El Paso, KMI and its affiliates and our general partner, we will reimburse KMI and its affiliates for the payment of operating and capital expenses related to our operations and for the provision of various general and administrative services for our benefit, including costs for rendering administrative staff and support services to us, and overhead allocated to us, including pension and health care costs which amounts will be determined by KMI and its affiliates in good faith. Payments for these services will be substantial and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units and restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. The limitation and definition of these duties is permitted by the Delaware law governing limited partnerships. The defined fiduciary standards are more limited than those that would apply under Delaware law in the absence of such definition.

Unitholders cannot remove our general partner without its consent.

The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove our general partner. Our unitholders are currently unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent the general partner's removal. In addition, under certain circumstances the successor general partner may be required to purchase the combined general partner interest and incentive distribution rights of the removed general partner, or alternatively, such interests will be converted into common units.

Our general partner may elect to cause us to issue Class B common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or holders of our common units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner holds all of our incentive distribution rights which provide the right to elect to relinquish the receipt of incentive distribution payments based on the initial cash target distribution levels and to reset (on the satisfaction of certain conditions) minimum quarterly and cash target distributions at higher levels that the general partner would be entitled to receive. In connection with resetting these target distribution levels, our general partner would be entitled to receive a number of Class B common units. The Class B common units would be entitled to the same cash distributions per unit as our common units and would be convertible into an equal number of common units.

In April 2012, the conditions were met which entitled our general partner to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are set. The reset election has not been made, however we anticipate that our general partner will exercise the right in the future to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It however, is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B common units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their member interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with their own choices and to control the decisions taken by the board of directors and officers of the general partner. This effectively permits a change of control of the partnership without unitholders' vote or consent.

We may issue additional units without approval which would dilute existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;

- the ratio of taxable income to distributions may increase;
- new classes of securities could be issued that provide preferences to the new class in relation to existing unitholders, including preferences on distributions of available cash, distributions upon our liquidation and voting rights;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 75% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders would be required to sell common units at an undesirable time or price and may not receive any return on investment. Unitholders might also incur a tax liability upon a sale of such units.

Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we may no longer be subject to the reporting requirements of the Securities Exchange Act of 1934. Our general partner and its affiliates own approximately 41% of our outstanding common units at December 31, 2013.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. The partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Unitholder liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute “control” of our business.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by affiliates of our general partner.

As of January 31, 2014, we had 217,831,642 common units outstanding, which includes 90,320,810 common units held by affiliates of our general partner. Sales by any of our existing unitholders, including affiliates of our general partner, of a substantial number of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold, subject to certain limitations.

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

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

Tax Risks to Common Unitholders

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

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

Despite the fact that we are a limited partnership under Delaware law, it is possible under certain circumstances for such an entity to be treated as a corporation for U.S. federal income tax purposes. Although we do not believe, based on our current operations, that we are or will be so treated, the IRS could disagree with the positions we take or a change in our business (or a change in current law) could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Moreover, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws or interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our common unitholders.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We will be considered to have technically terminated as a partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within any twelve-month period. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could also result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income being includable in the common unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

The IRS has announced a publicly traded partnership technical termination relief procedure, whereby, if a publicly traded partnership that has a technical termination requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the technical termination.

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

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

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

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

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

See Note 9 to our consolidated financial statements.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

PART II

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

The following table reflects the quarterly high and low sales prices for our common units based on the daily composite listing of stock transactions for the NYSE and the cash distributions per unit we declared for each period:

	Price Range		Declared cash distributions for the quarter
	High	Low	
2013			
First Quarter	$ 44.19	$ 37.30	$ 0.62
Second Quarter	44.99	39.04	0.63
Third Quarter	44.85	39.90	0.65
Fourth Quarter	43.04	33.34	0.65
2012			
First Quarter	$ 38.10	$ 33.34	$ 0.51
Second Quarter	35.42	30.64	0.55
Third Quarter	37.43	33.26	0.58
Fourth Quarter	38.65	33.64	0.61

Distribution information is for distributions declared for the respective quarter. The declared distributions were paid within 45 days after the end of the quarter.

Our common units are traded on the NYSE under the symbol "EPB." As of January 31, 2014, we had 53 unitholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

For information on our equity compensation plans, see Item 12 “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” and Item 11 “Executive Compensation— Long-Term Incentive Plan.”

We did not repurchase any units during the fourth quarter of 2013 or sell any unregistered units in the fourth quarter of 2013.

Item 6. ***Selected Financial Data.***

The following tables set forth, for the periods and at the dates indicated, our summary historical financial and operating data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report for more information.

	As of or for the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except per unit amounts)				
Income and Cash Flow Data:					
Revenues	$ 1,505	$ 1,515	$ 1,531	$ 1,454	$ 1,231
Operating income	895	863	849	819	656
Net income	610	589	605	666	542
Net income attributable to El Paso Pipeline Partners, L.P.	610	579	512	418	357
Net income attributable to El Paso Pipeline Partners, L.P. per limited partner unit-basic and diluted:					
Common units	1.86	2.15	2.03	1.90	1.64
Subordinated units(a)	—	—	—	1.78	1.56
Per unit cash distributions declared for the period (b)	2.55	2.25	1.93	1.63	1.36
Per unit cash distributions paid in the period (b)	2.51	2.14	1.87	1.55	1.33
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	$ 5,879	$ 5,931	$ 6,040	$ 6,051	$ 5,781
Total assets	6,495	6,581	6,679	6,569	6,565
Long-term debt	4,171	4,246	4,028	3,580	2,732

(a) All subordinated units were converted into common units on a one-for-one basis effective January 3, 2011. See Note 7 to our consolidated financial statements for further information.

(b) Distributions for the fourth quarter of each year are declared and paid in the first quarter of the following year.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties" and (ii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

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

General

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

- helping customers by providing safe and reliable transportation and storage of natural gas; and
- creating long-term value for our unitholders.

To achieve these objectives, we focus on providing fee-based services to customers from a business portfolio consisting of natural gas pipelines, related storage facilities and an LNG terminal.

Our revenues are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. Our long-term transportation contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Our LNG terminal capacity is similarly subscribed under long-term contracts, which are based on reservation charges (with little impact by changes in usage at the terminal). As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas.

Our Business

We are a Delaware MLP formed in 2007 to own and operate interstate natural gas transportation, storage and terminaling facilities. We own WIC, CIG, SLNG, Elba Express, SNG, SLC and CPG. Our primary business consists of interstate transportation and storage of natural gas. Our pipeline operations are rate-regulated and accordingly, we generate profit based on our ability to earn a return in excess of our costs through the rates we charge our customers.

Factors influencing profitability

Our long-term profitability will be influenced primarily by the following factors:

- Executing successfully on our expansion projects and developing growth projects in our market and supply areas;
- Contracting and recontracting pipeline capacity with our customers;
- Maintaining or obtaining approval by the FERC of acceptable rates, terms of service and expansion projects;
- Maintaining a high level of operating efficiency; and
- Pursuing strategic asset acquisitions from KMI and third parties to grow our business.

Types of Revenue

Each of our subsidiaries faces varying degrees of competition from other existing and proposed pipelines and LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil.

Our revenues consist of the following types:

		Percent of Total Revenues in 2013(a)						
Type	**Description**	**WIC**	**CIG**	**SLNG**	**Elba Express**	**SNG**	**CPG**	**EPB Consolidated**
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline systems and storage facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts.	100%	92%	95%	100%	90%	100%	93%
Usage and Other	Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn.	—%	8%	5%	—%	10%	—%	7%

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(a) Excludes liquids transportation revenue and base gas sales. In the case of CIG, liquids revenue associated with CIG's processing plant is also excluded. The revenues described in this table constitute approximately 97% of EPB's, 96% of SNG's, 94% of CIG's and 100% of WIC's, SLNG's, Elba Express' and CPG's total revenues.

The FERC regulates the rates we can charge our customers. These rates are generally a function of the cost of providing services to our customers, including a reasonable return on our invested capital. Because of our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices, changes in supply and demand, regulatory actions, competition, declines in the creditworthiness of our customers and weather.

We continue to manage the process of renewing expiring contracts to limit the risk of significant impacts on revenues. Our contracts mature at various times and in varying amounts of throughput capacity. The ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and the market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. We attempt to recontract or remarket capacity at the maximum rates allowed under their respective tariffs, although at times, we enter into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems. As of December 31, 2013, the remaining weighted average contract life of our natural gas transportation and LNG contracts was approximately 8 years and 19 years, respectively.

Below is the contract expiration portfolio and the associated revenue expirations for our firm transportation contracts on our wholly owned systems as of December 31, 2013, including those with terms beginning in 2013 or later:

	Contracted Capacity	Percent of Total Contracted Capacity	Reservation Revenue	Percent of Total Reservation Revenue
	(BBtu/d)	(%)	(In millions)	(%)
2014	566	4%	$ 16	1%
2015	1,534	10%	89	8%
2016(a)	3,496	24%	325	29%
2017	833	6%	56	5%
2018	1,393	10%	108	9%
2019 and beyond	6,735	46%	543	48%
Total	14,557	100%	$ 1,137	100%

(a) Includes contracts of 1,533 BBtu/d for $191 million that were extended in conjunction with SNG’s rate case settlement approved by the FERC in July 2013 and contracts of 1,301 BBtu/d for $94 million that were extended in conjunction with CIG's rate case settlement approved by the FERC in August 2011.

Growth Projects

Elba Express Phase B Expansion

The Elba Express Phase B Expansion was placed in service in April 2013, adding 10,000 horsepower at a new compressor station located in Hart County, Georgia. The expansion allows Elba Express to receive up to 220 MMcf/d of natural gas supplies from existing interconnections with Transcontinental Gas Pipe Line Company, LLC for deliveries to markets in the southeast.

Liquefaction Project

Elba Island Liquefaction Project. In January 2013, SLC, a subsidiary of EPB and Shell US Gas & Power LLC (Shell G&P), a subsidiary of Shell, formed ELC to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal. In connection with the formation of ELC, SLC and Shell G&P entered into a LLC agreement in which SLC owns 51% of ELC and Shell G&P owns the remaining 49%. Under the terms of the LLC agreement, SLC and Shell G&P are both obligated to make certain capital contributions in proportion to their membership interests in ELC to fund the construction of the liquefaction facilities. SLNG has received DOE authorization to export the produced LNG to FTA countries and has applied for non-FTA approval. Phase I of the project will have capacity of approximately 210 MMcf/d (1.5 million tonnes per year) and requires no additional DOE approval. As part of Phase I, we also expect to incur additional capital expenditures related to ancillary facilities on SLNG's terminal. EPB's total estimated investment at the terminal in Phase I is approximately $800 million. In November 2013, Shell G&P exercised part one of a two-part option for ELC to build Phase II of the project. Capacity to be added in Phase II will be either 70 MMcf/d (0.5 million tonnes per year) or 140 MMcf/d (1.0 million tonnes per year) at Shell G&P’s election. Our share of the estimated capital expenditure of Phase II at 140 MMcf/d is approximately $224 million.

In January 2013, ELC signed a liquefaction services agreement with Shell NA LNG LLC (Shell LNG) to provide liquefaction services. Once the project is finalized, Shell LNG will subscribe to 100% of the liquefaction capacity pertaining to Phases I and II of the aforementioned project. Subject to various regulatory approvals, SLNG will modify its LNG terminal to load the LNG onto ships for export. SLNG entered into a Maintenance, Administrative and Operating Agreement with ELC in which SLNG has agreed to perform operation, maintenance and administrative services associated with the construction and operation of the liquefaction facilities. We expect to file full project applications with the FERC near the end of the first quarter in 2014.

Elba Express and SNG expansions

Elba Express and SNG will invest up to $279 million to expand their systems following successful open seasons held in August 2013 for incremental, long-term natural gas transportation service. The open seasons generated customer interest in incremental capacity of greater than 700,000 Dth/d that will support southeastern infrastructure growth and the needs of customers in Georgia, South Carolina and northern Florida.

Elba Express expansion. The Elba Express expansion will create incremental north-to-south capacity, including interconnects and delivery points with SNG and other pipelines and shippers, designed to serve a new load created by the proposed Elba Liquefaction Project at SLNG's Elba Island Terminal near Savannah, Georgia and other capacity needs along the Elba Express Pipeline. Elba Express customers have expressed interest in a later phase to the Elba Express project that could add incremental capacity of approximately 300,000 Dth/d, which, if constructed, would bring the total capacity of the expansions to approximately 1.0 Bcf/d. Elba Express expects an in-service date as early as June 2016 pending regulatory approvals.

SNG expansion. The SNG expansion will create capacity on its South Main system and also provide subscribing customers firm north-to-south transportation service on the Elba Express Pipeline using firm transportation service being acquired by SNG in the Elba Express expansion. SNG anticipates placing the project in service in 2016, pending regulatory approvals.

We continue to evaluate additional expansion opportunities around our assets. We have other prospective projects that are in various phases of commercial development. Many of these potential projects involve expansion capacity to serve increased natural gas-fired generation loads or to adapt to changing supply profiles resulting from burgeoning shale gas development, declines in LNG imports and potential LNG exports. If we are successful in contracting for these new loads, the capital requirements could be substantial and would be incremental to our contracted growth projects. Although we pursue the development of these potential projects from time to time, there can be no assurance that we will be successful in negotiating the definitive binding contracts necessary for such projects to be included in our contracted growth projects.

Critical Accounting Estimates

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

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) the economic useful lives of our assets; (ii) asset impairment charges; (iii) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (iv) provisions for uncollectible accounts receivables; (v) exposures under contractual indemnifications; and (vi) unbilled revenues.

For a summary of our significant accounting policies, see Note 2 to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others. Below are such significant accounting policies.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on our environmental disclosures, see Note 9 to our consolidated financial statements.

Legal Matters

We are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on our disclosure of legal matters, see Note 9 to our consolidated financial statements.

Cost-Based Regulation

We account for our regulated operations in accordance with current FASB accounting standards for rate-regulated operations . The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by a non-regulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management regularly assesses whether regulatory assets are probable of future recovery or if regulatory liabilities are probable of being refunded to our customers by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. We periodically evaluate the applicability of accounting standards related to regulated operations, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to reduce certain of our asset balances to reflect a market basis lower than cost and write-off the associated regulatory assets.

Accounting for Other Postretirement Benefits

We reflect an asset or liability for our subsidiaries' postretirement benefit plan based on its overfunded or underfunded status. As of December 31, 2013, our postretirement benefit plan was overfunded by $45 million. Our postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rates used in calculating the benefit obligations. We select our discount rate by matching the timing and amount of our expected future benefit payments for our postretirement benefit obligation to the average yields of various high-quality bonds with corresponding maturities.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with the postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations, along with changes to the plan and other items, are deferred and recorded as either accumulated other comprehensive income or a regulatory asset or liability depending on whether these costs are recoverable through rates.

A one-percentage point change in the assumed health care trends would not have a significant effect on net postretirement benefit cost or the funded status. A one-percentage point change in the discount rate would not have a significant effect on net postretirement benefit cost and would have the following impact on the funded status for the year ended December 31, 2013 (in millions):

	Increase (Decrease) in Funded Status
One percent increase in:	
Discount rates	$3
One percent decrease in:	
Discount rates	(3)

For more information on postretirement benefits, see Note 6 to our consolidated financial statements.

Asset and Investment Impairments

The accounting rules on asset and investment impairments require us to continually monitor our businesses, the business environment and the performance of our investments to determine if an event has occurred that indicates that a long-lived asset or investment may be impaired. Such events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. The assessment of project level cash flows requires significant judgment to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors that are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can, and often do, differ from our estimates. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

Results of Operations

Non-GAAP Measures

The non-GAAP financial measures, DCF before certain items and EBDA before certain items, are presented below under Distributable Cash Flow and Earnings Results, respectively. Certain items are items that are required by GAAP to be reflected in net income, but typically either do not have a cash impact, or by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically.

Our non-GAAP measures described below should not be considered as an alternative to GAAP net income, operating income or any other GAAP measure. DCF before certain items and EBDA before certain items are not financial measures in accordance with GAAP and have important limitations as analytical tools. You should not consider either of these non-GAAP measures in isolation or as a substitute for an analysis of our results as reported under GAAP. Because DCF before certain items excludes some but not all items that affect net income and because DCF measures are defined differently by different companies in our industry, our DCF before certain items may not be comparable to DCF measures of other companies. EBDA before certain items has similar limitations. Our management compensates for the limitations of these non-GAAP measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making process.

Distributable Cash Flow

Our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves). DCF is an overall performance metric we use as a measure of available cash. Because we distribute all of our available cash to investors, our primary objective is to grow cash distributions over time. We believe the primary measure of company performance used by us, investors and industry analysts covering MLPs is cash generation performance. Therefore, we believe DCF is our most important measure to evaluate the operating and financial performance of the partnership and to compare it with the performance of other publicly traded MLPs within the industry.

We define DCF before certain items to be limited partners' income before certain items and DD&A, less sustaining capital expenditures (those capital expenditures which do not increase the capacity or throughput), plus our share of DD&A less our share of sustaining capital expenditures for our equity method investees, plus other income and expenses, net (which primarily includes deferred revenue, non-cash AFUDC equity and other items).

Our DCF was $569 million, $590 million and $483 million for the years ended December 31, 2013, 2012 and 2011, respectively. The decrease in DCF of $21 million in 2013 as compared to 2012 was primarily due to higher general partner's incentive distributions and the SNG and WIC rate case settlements partially offset by contributions from the 2012 acquisition of CPG and the remaining ownership interest in CIG, higher revenue due to SNG's Phase III of the South System III expansion project placed in service in June 2012 and the Elba Express Phase B Expansion project placed in service in April 2013 and lower spending of sustaining capital expenditures. Our increase in DCF of $107 million in 2012 as compared to 2011 was primarily due to our acquisition of CPG, increased ownership interests in SNG and CIG during 2011 and 2012 and a decrease in sustaining capital expenditures.

The table below details the reconciliation of DCF to Net Income (in millions):

	Year Ended December 31,		
	2013	**2012**	**2011**
Net Income	$ 610	$ 589	$ 605
Net income attributable to noncontrolling interests	—	(10)	(93)
Net income attributable to El Paso Pipeline Partners, L.P.	610	579	512
Certain items:			
CPG pre-acquisition earnings	—	(22)	(40)
Project cancellation payment	—	—	(14)
Loss on write-off of asset	—	11	—
CIG environmental reserve adjustment	—	(6)	—
Non-cash severance costs (a)	1	34	—
SNG offshore assets hurricane repair costs	2	—	—
Sales and use tax reserve adjustment	2	—	—
Subtotal certain items	5	17	(54)
Net income attributable to El Paso Pipeline Partners, L.P. before certain items	615	596	458
Less: General Partner’s 2% interest allocation	(12)	(12)	(9)
General Partner’s incentive distribution	(195)	(129)	(62)
Limited Partners’ Net Income before certain items	408	455	387
Add/(Subtract):			
Depreciation and amortization (b)	198	178	169
Net income attributable to noncontrolling interests before certain items	—	10	79
Declared distributions to noncontrolling interests before certain items	—	(8)	(47)
Sustaining capital expenditures (b)	(39)	(46)	(103)
Other, net (c)	2	1	(2)
	161	135	96
Distributable Cash Flow before certain items—Limited Partners	$ 569	$ 590	$ 483

(a) The amounts reflect the non-cash severance costs allocated to us from El Paso as a result of KMI’s acquisition of El Paso; however, we do not have any obligation nor did we pay any amounts related to this expense.

(b) Includes our share of equity method investee's depreciation and amortization or sustaining capital expenditures.

(c) Includes deferred revenue and certain non-cash items such as AFUDC equity and other items.

Earnings Results

Our management assesses our performance based on EBDA, which excludes DD&A, general and administrative expenses and interest expense, net. Certain general and administrative expenses have been excluded from EBDA such as employee benefits, legal, information technology and other costs that are not controllable by operating management and thus are not included in the measure of performance for which they are accountable. Our management uses EBDA as a measure to assess the operating results and effectiveness of our assets, which consist of both consolidated operations and earnings from equity method investments. We believe providing EBDA to our investors is useful because it is the same measure used by management to evaluate our performance and allows investors to evaluate our operating results without regard to our financing methods or capital structure. EBDA may not be comparable to measures used by other companies. Additionally, EBDA should be considered in conjunction with net income and other performance measures such as operating income or operating cash flows.

Below are the components of EBDA for the periods presented (in millions):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 1,505	$ 1,515	$ 1,531
Operating Expenses			
Operations and maintenance	(329)	(387)	(419)
General and administrative expenses	83	139	132
Operations and maintenance, excluding general and administrative expenses	(246)	(248)	(287)
Taxes, other than income taxes	(83)	(82)	(83)
Operating Expenses	(329)	(330)	(370)
Earnings from equity investments	13	14	15
Other, net	2	5	8
EBDA	$ 1,191	$ 1,204	$ 1,184

Below is a reconciliation of our EBDA to net income attributable to EPB, our throughput volumes and an analysis and discussion of our operating results for the periods presented (in millions, except operating statistics):

	Year Ended December 31,		
	2013	2012	2011
EBDA(a)(b)(c)(d)	$ 1,191	$ 1,204	$ 1,184
Depreciation and amortization(e)	(198)	(183)	(180)
General and administrative expenses(f)	(83)	(139)	(132)
Interest expense, net(g)	(300)	(293)	(267)
Net income	610	589	605
Net income attributable to noncontrolling interests	—	(10)	(93)
Net income attributable to EPB	$ 610	$ 579	$ 512
Throughput volumes (BBtu/d)(h)	7,498	7,864	7,364

(a) 2013 includes a $4 million decrease in EBDA related to the following certain items:
- a $2 million decrease in EBDA, included in operating expenses, related to SNG's sales and use tax audit interests and penalties; and
- a $2 million decrease in EBDA, included in operating expenses, related to hurricane repair costs for the SNG offshore assets.

(b) 2012 includes a $29 million increase in EBDA related to the following certain items:
- $34 million increase of pre-acquisition EBDA related to CPG (comprised of $45 million of revenues and $11 million of operating expenses);
- $11 million charge to operating expenses attributable to a canceled software implementation project; and
- $6 million non-cash adjustment reducing operating expenses for environmental liabilities associated with certain CIG environmental projects.

(c) 2011 includes a $99 million increase in EBDA related to the following certain items:
- $85 million increase of pre-acquisition EBDA related to CPG (comprised of $112 million of revenues and $27 million of operating expenses);
- $17 million of revenue resulting from BG LNG's cancellation of its commitment to Phase B of SLNG's Elba III Expansion; and
- $3 million charge to operating expenses due to the write-off of project development costs incurred in conjunction with the aforementioned Elba Express expansion project.

(d) 2013, 2012 and 2011 includes within Other, net $2 million, $3 million and $7 million, respectively, of an allowance for equity funds used during construction.

(e) Includes pre-acquisition depreciation and amortization expense for CPG of $5 million in 2012 and $12 million in 2011.

(f) Includes certain items as follows:
- pre-acquisition general and administrative expenses for CPG of $3 million in 2012 and $8 million in 2011; and
- non-cash severance costs of $1 million and $34 million in 2013 and 2012, respectively allocated to us from El Paso as a result of KMI's acquisition of El Paso; however, we do not have any obligation nor did we pay any amounts related to this expense.

(g) Includes pre-acquisition interest expense, net for CPG of $4 million for 2012 and $11 million for 2011.

(h) Throughput volumes are presented for WIC, CIG, SNG, CPG and Elba Express and exclude intrasegment volumes. The average daily volumes transported on Elba Express during 2012 and 2011 were not material.

EBDA

Combined, the items described in footnotes (a) and (b) above decreased our EBDA by $33 million for 2013 as compared to the same period in 2012 and footnotes (b) and (c) decreased our EBDA by $70 million for 2012 as compared to the same period in 2011. Following is information related to the remaining changes in EBDA and revenues for 2013 compared to the corresponding period in 2012 and 2012 compared to the corresponding period in 2011 (in millions):

	2013 vs. 2012		2012 vs. 2011	
	EBDA	Revenues	EBDA	Revenues
	increase/(decrease)			
CPG	$ 31	$ 40	$ 51	$ 62
SNG	(16)	12	26	21
Elba Express	17	17	1	—
WIC	(12)	(30)	4	—
Other	—	(4)	8	(15)
Total EPB	$ 20	$ 35	$ 90	$ 68

Year Ended December 31, 2013 versus Year Ended December 31, 2012

EBDA

After adjusting for the certain items described in footnotes (a) and (b) above, our 2013 EBDA increased by $20 million as compared to 2012 primarily due to the following:

- The CPG acquisition contributed $31 million of incremental EBDA (comprised of $40 million of higher revenues and $9 million of higher operating expenses) for the year ended December 31, 2013 as compared to the 2012 post-acquisition period. See Note 3 to our consolidated financial statements for additional information regarding the acquisition of CPG;

- SNG's EBDA decreased $16 million for 2013 as compared to 2012 (comprised primarily of $12 million of higher revenues and $25 million of higher operating expenses). SNG experienced $20 million of higher revenues during 2013 due to the sale of cushion gas from one of its storage facilities partially offset by $12 million of associated cost of sale. The South System III Phase III Expansion project, which was completed and placed in service in June 2012, contributed $7 million of higher revenues for 2013 partially offset by lower AFUDC equity of $2 million. In addition, EBDA was unfavorably impacted by lower usage revenues of $4 million primarily due to lower throughput volumes caused by reduced electrical power generation and $11 million of lower reservation and other service revenues due to rate reductions pursuant to SNG's rate case settlement as further discussed in Note 11 to our consolidated financial statements. SNG experienced $15 million of higher operating expenses during 2013 primarily due to higher field operation and maintenance expenses due to increased pipeline integrity costs, favorable 2012 gas balance revaluations and higher property taxes due to plant additions and refunds received in 2012;

- Elba Express contributed higher EBDA of $17 million for 2013 as compared to 2012 primarily due to higher revenues resulting from the placement of the Elba Express Phase B Expansion project in service in April 2013;

- WIC's EBDA decreased by $12 million for 2013 as compared to 2012. WIC was unfavorably impacted by lower revenues of $7 million largely due to the nonrenewal of expiring contracts and restructuring of certain contracts at lower volumes or discounted rates. Additionally, in December 2012, WIC terminated some of its seamless single nomination services that previously provided natural gas deliveries through WIC and interconnected third party pipeline systems for certain customers, which for 2013 resulted in lower revenue of $18 million and a corresponding offset within EBDA of lower transportation expense of $18 million associated with the third party service providers. During 2013, WIC experienced lower revenues of $4 million due to rate reductions pursuant to its Section 5 rate settlement. See Item Part IV Item 15. Financial Statements, Note 11 “Accounting for Regulatory Activities” for further information related to WIC's rate proceeding;

- CIG, which is included in Other, was unfavorably impacted by lower transportation revenues of $11 million for 2013 as compared to 2012 largely due to the nonrenewal of expiring contracts and the restructuring of certain contracts at lower volumes or discounted rates. Offsetting this unfavorable impact were storage gas sales of $5 million and higher revenues of $6 million for 2013 attributable to the revenue surcharge mechanism (which enables us to make estimated customer billing surcharge accruals with certain customers when realized revenue is less than the annual threshold amounts as established in CIG's August 2011 rate case settlement); and

- SLNG, which is included in Other, was favorably impacted by lower electricity and dredging costs of $7 million in 2013 as compared to 2012. This favorable variance was partially offset by lower electric and net dredging tracker revenues of $5 million due to lower volumes and dredging rates during 2013.

Depreciation and Amortization

After adjusting for the items described in footnote (e) above, our depreciation and amortization expense was $20 million higher in 2013 as compared to 2012 primarily due to the amortization of deferred losses on SNG's November 2012 sale of offshore assets and increased property, plant and equipment additions related to expansion projects placed in service during 2012 and 2013. For a further discussion of the amortization of deferred losses on SNG's sale of offshore assets, see Note 3 to our consolidated financial statements.

General and Administrative Expenses

After adjusting for the items described in footnote (f) above, general and administrative expenses were lower by $20 million in 2013 as compared to 2012 primarily due to lower corporate allocations resulting from realization of synergies and cost savings associated with KMI's acquisition of El Paso.

Interest Expense, net

After adjusting for the items described in footnote (g) above, interest expense, net, increased by $11 million in 2013 as compared to 2012 primarily due to the November 2012 issuance of the $475 million senior notes by EPPOC, which was used to pay down its revolving credit facility borrowings partially offset by lower revolver borrowings in 2013 and various EPPOC debt repayments made for debt maturing throughout 2012 and 2013. Also driving the higher interest expense was the amortization of the loss related to the early repayment of the CPG term loan in September 2012. For a further discussion of these debt obligations, see Note 5 to our consolidated financial statements.

Net Income Attributable to Noncontrolling Interests

Our net income attributable to noncontrolling interests decreased in 2013 as compared to 2012 primarily due to our acquisition of the remaining interest in CIG in May 2012.

Year Ended December 31, 2012 versus Year Ended December 31, 2011

EBDA

After adjusting for the certain items described in footnotes (b) and (c) above, our 2012 EBDA increased by $90 million as compared to 2011 primarily due to the following:

- The CPG acquisition contributed $51 million of incremental EBDA for the year ended December 31, 2012 (reflecting CPG's EBDA results for the May 25 to December 31, 2012 post-acquisition period). See Note 3 to our consolidated financial statements for additional information regarding the acquisition of CPG;

- SNG contributed higher EBDA of $26 million primarily due to higher revenues of $21 million primarily from the completion of Phases II and III of the South System III expansion project in June 2011 and June 2012 and lower operating expenses of $9 million mainly due to reduced fuel costs in 2012;

- CIG, which is included in Other, contributed additional EBDA of $6 million in 2012 as compared to 2011 largely due to favorable property tax adjustments of $4 million during 2012, lower pipeline maintenance, payroll and contractor costs of $10 million, which impacted operating expenses, and increased reservation revenue of $7 million related to an expansion project placed in service in October 2011. Partially offsetting these favorable impacts were lower transportation revenues of $15 million primarily resulting from the non renewal of expiring contracts, the restructuring of certain contracts at lower volumes or discounted rates and lower usage and interruptible revenues due to milder weather; and

- WIC contributed additional EBDA of $4 million in 2012 as compared to 2011 primarily due to higher operating expenses related to compressor station repairs performed in 2011.

Depreciation and Amortization

After adjusting for the items described in footnote (e) above, our depreciation and amortization expense was $10 million higher in 2012 as compared to 2011 primarily due to increased property, plant and equipment additions related to expansion projects placed in service during 2012 and 2011.

General and Administrative Expenses

After adjusting for the items described in footnote (f) above, general and administrative expenses were $22 million lower in 2012 as compared to 2011 primarily due to lower benefit costs resulting from acquisition-related employee headcount reductions.

Interest Expense, net

After adjusting for the items described in footnote (g) above, interest expense, net, increased by $33 million in 2012 as compared to 2011 primarily due to higher average debt outstanding used to fund acquisitions and expansion projects. The increase in our average debt outstanding was attributable to the revolving credit facility borrowings to fund the May 2012 CPG acquisition, the November 2012 issuance of $475 million senior notes by EPPOC, the debt issuances of $500 million senior notes by EPPOC in September 2011 and $300 million senior notes by SNG in June 2011. For a further discussion of these debt obligations, see Note 5 to our consolidated financial statements.

Net Income Attributable to Noncontrolling Interests

Our net income attributable to noncontrolling interests decreased in 2012 as compared to 2011 primarily due to our acquisition of incremental interests in SNG and CIG in 2011 and 2012.

Liquidity and Capital Resources

General

As of December 31, 2013, we had approximately $1.1 billion of liquidity consisting of $1.0 billion of availability under our revolving credit agreement and $78 million of cash on hand. We expect our current liquidity sources and operating cash flow to be sufficient to fund our estimated 2014 capital program, as illustrated in the "Capital Expenditures" table below. We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements.

Our primary sources of cash include cash flow from operations and funds obtained through long-term financing activities and bank credit facilities. Our primary uses of cash are funding capital expenditure programs, meeting our debt service obligations, meeting operating needs and paying distributions. Our outstanding short-term debt as of December 31, 2013 was $77 million, consisting of $71 million in SLNG senior notes and $6 million in other financing obligations. We intend to refinance our current maturities through issuance of a combination of long-term debt and equity and/or borrowings under our revolving credit facility. We may generate additional sources of cash through future issuances of additional partnership units, including issuances under the equity distribution agreement, and/or future debt offerings.

To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt obligations and our debt-related transactions during 2013, see Note 5 to our consolidated financial statements. For information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk."

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

Credit Ratings and Capital Market Liquidity

Our credit ratings affect our ability to access the public and private debt markets, as well as the terms and pricing of our debt (see Part I, Item 1A “Risk Factors”). Based on our senior unsecured credit ratings as discussed below, we expect that our respective short-term liquidity needs will be met primarily through short-term borrowings. Nevertheless, our ability to satisfy financing requirements or fund planned capital expenditures (including planned expenditures of our joint ventures) will depend upon future operating performance, which will be affected by prevailing economic conditions in the energy pipeline industry and other financial and business factors, some of which are beyond our control. Our debt ratings are as follows:

Rating Agency	Rating	Date of Last Change	Outlook	Date of Last Change
Standard and Poor's	BBB-	May 24, 2012	Positive	May 31, 2013
Moody's Investor Services	Ba1	March 25, 2010	Positive	February 27, 2013
Fitch Ratings	BBB-	March 25, 2010	Stable	N/A

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash, as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. We declared a total cash distribution of $2.55 per unit for the year ended December 31, 2013. This distribution is 13% higher than the $2.25 per unit distribution we declared in 2012. Our declared distribution for the year ended December 31, 2013 of $2.55 per unit will result in an IDR payment to our general partner of $195 million. Comparatively, our distribution of $2.25 per unit declared in 2012 resulted in an IDR payment to our general partner in the amount of $129 million.

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. Capital expenditures under our partnership agreement include those that are maintenance/sustaining capital expenditures and those that are capital additions and improvements (which we refer to as expansion or discretionary capital expenditures). These distinctions are used when determining cash from operations pursuant to the partnership agreement (which is distinct from GAAP cash flows from operating activities). Capital additions and improvements are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating cash from operations. Maintenance capital expenditures are those which maintain throughput or capacity. Thus, under our partnership agreement, the distinction between maintenance capital expenditures and capital additions and improvements is a physical determination rather than an economic one.

Generally, the determination of whether a capital expenditure is classified as maintenance or as capital additions and improvements are made on a project level. The classification of capital expenditures as capital additions and improvements or as maintenance capital expenditures under our partnership agreement is left to the good faith determination of the general partner, which is deemed conclusive.

Our capital expenditures for the year ended December 31, 2013, and the amount we expect to spend for 2014 to sustain and grow our businesses are as follows (in millions):

	2013(a)(b)	Expected 2014(b)
Sustaining	$ 39	$ 47
Discretionary	111	169
Total	$ 150	$ 216

(a) Includes a net increase in capital accruals and retainage of $7 million.
(b) Includes capitalized AFUDC and our share of equity method investees' capital expenditures.

We generally fund our sustaining capital expenditures with existing cash or from cash flows from operations. Generally, we initially fund our discretionary capital expenditures through borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively replace the initial funding with long-term debt, equity or both.

We report our total consolidated capital expenditures separately as "Capital expenditures" within the "Cash flows from Investing Activities" section on our accompanying cash flow statements, and the overall $16 million year-to-year increase in our consolidated capital expenditures in 2013 versus 2012, was primarily due to increased expenditures related to the SNG and Elba Express expansions, as well as the ancillary facilities at SLNG, as further discussed in "Growth Projects."

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

Cash Flow

The following table summarizes our net cash flows from operating, investing and financing activities for each period presented (in millions):

	2013	2012	increase/(decrease)
Net cash provided by (used in):			
Operating activities	$ 858	$ 716	$ 142
Investing activities	(142)	(249)	107
Financing activities	(752)	(473)	(279)
Net decrease in cash and cash equivalents	$ (36)	$ (6)	$ (30)

Operating Activities. Cash provided by operating activities before changes in operating assets and liabilities was $5 million lower than the comparative prior year period primarily due to lower revenues resulting from SNG's and WIC's rate case settlements and nonrenewal of expiring contracts partially offset by placement of the South System III Phase III Expansion project and the Elba Express Phase B Expansion in service in June 2012 and April 2013, respectively. In addition, changes in operating assets and liabilities provided higher cash of $147 million primarily due to the timing of our customer collections, the increase in fuel recovery in 2013, the termination of the accounts receivable sales program in June 2012 and the reduction in payments to affiliates due to lower allocated costs.

Investing Activities. Our cash flow from investing activities increased primarily due to the impact of the cash outlay of $185 million (representing CPG's book value) made during May 2012 to purchase CPG, as further discussed in Note 3 to our consolidated financial statements. Offsetting our cash outlay are the proceeds from the sale of certain SNG non-core offshore assets with proceeds of $50 million received in 2012 more fully described in Note 3 to our consolidated financial statements.

Financing Activities. During 2013, we received $87 million of net proceeds from our common and general partner unit issuances as compared to the $279 million in 2012. During 2012, we paid $206 million to acquire the remaining interest in CIG and an additional $180 million of excess cash over contributed book value for CPG as further discussed in Note 3 to our consolidated financial statements. We borrowed $805 million from our revolving credit facility during 2012 of which $570 million was used to fund the acquisition. We had $469 million in net proceeds from the EPPOC debt issuance in November 2012. In addition, our subsidiaries distributed $28 million to El Paso in 2012 as discussed in Note 8 to our consolidated financial statements. Furthermore, we repaid CPG's debt of $172 million in 2012 and EPPOC's debt of $60 million and $88 million in 2012 and 2013, respectively. We also paid $182 million of higher cash distributions to our partners in 2013 as compared to 2012, due to a greater number of partnership units outstanding, an increase in our cash distribution per unit and increased incentive distributions to our general partner.

Rate Case Settlements

See Item 15. Financial Statements, Note 11 "Accounting for Regulatory Activities" to our consolidated financial statements for information related to rate case settlements for WIC, SNG and CIG. These settlements are consistent with management's expectations and are not expected to materially impact our future cash flow projections, including our expected 2014 distributions.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet financing entities or structures with third parties other than our equity investments, as discussed in Note 1 to our consolidated financial statements.

Contractual Obligations

Contractual obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. The following table and discussion summarizes our contractual cash obligations as of December 31, 2013 for each of the periods presented (in millions):

Contractual Obligations	Due in Less Than 1 Year	Due in 1-3 Years	Due in 3-5 Years	Thereafter	Total
Long-term financing obligations					
Principal	$ 77	$ 825	$ 510	$ 2,844	$ 4,256
Interest	269	486	389	2,257	3,401
Other contractual liabilities	—	1	1	—	2
Operating leases	4	8	8	58	78
Capital commitments	17	—	—	—	17
Transportation and storage	36	57	57	89	239
Total	$ 403	$ 1,377	$ 965	$ 5,248	$ 7,993

Long-Term Financing Obligations (Principal and Interest)

Long-term financing obligations represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rates for fixed rate debt and (ii) current market interest rates and the contractual credit spread for our variable rate debt. Included in these amounts are payments related to the financing obligations of CIG for the construction of WYCO's High Plains pipeline and Totem gas storage facility. CIG makes monthly interest payments on these obligations that are based on 50% of the operating results of High Plains pipeline and Totem storage facility. Also included in these amounts is a compressor station under a capital lease from CIG's unconsolidated investment in WYCO. The compressor station lease expires in November 2029. For a further discussion of our long-term financing and capital lease obligations, see Note 5 to our consolidated financial statements.

Other contractual liabilities

Included in this amount are environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we perform remediation activities. These liabilities are included in non-current liabilities in our Consolidated Balance Sheets.

Operating Leases

For a further discussion of these obligations, see Note 9 to our consolidated financial statements.

Capital Commitments

Included in this amount are capital commitments related to our expansion projects as well as commitments for purchase of plant, property and equipment. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures. For a further discussion of these obligations, see Note 9 to our consolidated financial statements.

Transportation and Storage Commitments

Included in these commitments are transportation and storage agreements for capacity on third party pipeline systems and storage capacity from affiliates.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below. For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, we do not have an obligation to prepay fixed rate debt prior to maturity and, as a result, interest rate risk and changes in fair value should not have a significant impact on our fixed rate debt until we are required to refinance such debt.

As of December 31, 2013 and 2012, the carrying values of our fixed rate debt were $4,248 million and $4,339 million, respectively. These amounts compare to, as of December 31, 2013 and 2012, fair values of $4,616 million and $5,073 million, respectively. Fair values were determined using quoted market prices, where applicable, or future cash flow discounted at market rates for similar types of borrowing arrangements. We had no variable rate debt outstanding as of December 31, 2013 and 2012.

For additional information related to our debt obligations, see Note 5 to our consolidated financial statements.

Item 8. ***Financial Statements and Supplementary Data.***

The information required in this Item 8 is included in this report as set forth in the "Index to Financial Statements" on page 63.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure .***

None.

Item 9A. ***Controls and Procedures.***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2013, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item10. *Directors, Executive Officers and Corporate Governance .*

Directors and Executive Officers of our General Partner

Set forth below is information concerning the directors and executive officers of El Paso Pipeline GP Company, L.L.C., our general partner. All directors are elected annually by, and may be removed by, KMI, as the ultimate parent of its sole member. All officers of our general partner serve at the discretion of the board of directors of our general partner.

Name	Age	Position with El Paso Pipeline GP Company, L.L.C.
Richard D. Kinder	69	Director, Chairman and Chief Executive Officer
Steven J. Kean	52	Director, President and Chief Operating Officer
Thomas A. Martin	52	Director and Vice President (President, Natural Gas Pipelines)
Ronald L. Kuehn, Jr.	78	Director
Arthur C. Reichstetter	67	Director
William A. Smith	69	Director
Kimberly A. Dang	44	Vice President
David R. DeVeau	48	Vice President and General Counsel
David P. Michels	35	Vice President and Chief Financial Officer
Dax A. Sanders	38	Vice President, Corporate Development
Lisa Shorb	55	Vice President, Human Resources, Information Technology and Administration

Richard D. Kinder is Director, Chairman and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C., KMI, Kinder Morgan Management, LLC (KMR) and Kinder Morgan G.P., Inc. He was elected Director, Chairman and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C. in May 2012 and KMI in October 1999. Mr. Kinder has served as Director, Chairman and Chief Executive Officer of KMR since its formation in February 2001. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. in February 1997. He also served as Chief Manager, and as a member of the Board of Managers, of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Chairman and Chief Executive Officer of KMI upon its conversion. Mr. Kinder's experience as Chief Executive Officer of KMI, KMR, Kinder Morgan G.P., Inc. and the general partner of EPB, provide him with a familiarity with our strategy, operations and finances that can be matched by no one else. In addition, we believe that with Mr. Kinder's significant direct and indirect equity ownership in us, aligns his economic interests with those of our other stockholders.

Steven J. Kean is President and Chief Operating Officer of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. Mr. Kean was elected President and Chief Operating Officer of El Paso Pipeline GP Company, L.L.C., KMI, Kinder Morgan G.P., Inc. and KMR in January 2013, such election was effective in March 2013. He was Executive Vice President and Chief Operating Officer of El Paso Pipeline GP Company, L.L.C. from May 2012 to March 2013 and of KMI, Kinder Morgan G.P., Inc. and KMR from January 2006 until March 2013. Mr. Kean also served as Manager and Chief Operating Officer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Director, Executive Vice President and Chief Operating Officer of KMI upon its conversion. He has served in various management roles for the Kinder Morgan companies since 2002. Mr. Kean received his Juris Doctor from the University of Iowa in May 1985 and received a Bachelor of Arts degree from Iowa State University in May 1982. Mr. Kean's experience as one of our executives since 2002 provides him valuable management and operational expertise and a thorough understanding of our business operations and strategy.

Thomas A. Martin is Vice President (President, Natural Gas Pipelines) of El Paso Pipeline GP Company, L.L.C., KMR and Kinder Morgan G.P., Inc. Mr. Martin was elected Vice President (President, Natural Gas Pipelines) of El Paso Pipeline GP Company, L.L.C. in May 2012 and of KMR and Kinder Morgan G.P., Inc. in November 2009. Mr. Martin served as President, Texas Intrastate Pipeline Group from May 2005 until November 2009 and has served in various management roles for the Kinder Morgan companies since 2003. Mr. Martin received a Bachelor of Business Administration degree from Texas A&M University. Mr. Martin’s experience as president of Kinder Morgan’s natural gas pipelines business segment provide him valuable management and operational expertise and detailed knowledge of our business operations and strategy.

Ronald L. Kuehn, Jr. is Director of El Paso Pipeline GP Company L.L.C. Mr. Kuehn has been a Director of El Paso Pipeline GP Company L.L.C. since August 2007 and served as Chairman from August 2007 to May 2012. Mr. Kuehn previously served as Chairman of the Board of Directors of El Paso Corporation from March 2003 to May 2009 and Interim Chief Executive Officer from March 2003 to September 2003. From September 2002 to March 2003, Mr. Kuehn served as Lead Director of El Paso. From January 2001 to March 2003, he was a business consultant. Mr. Kuehn served as non-executive Chairman of the Board of El Paso from October 1999 to December 2000. Mr. Kuehn previously served as Chairman of the Board of Sonat Inc. from April 1986 and President and Chief Executive Officer from June 1984 until his retirement in October 1999. Mr. Kuehn formerly served on the Boards of Directors of Praxair, Inc. until 2008, Dun & Bradstreet Corporation until 2007 and Regions Financial Corporation until 2007. His knowledge and understanding of our industry provides the board of our general partner with valuable strategic insight. Mr. Kuehn's prior service on the boards of other publicly-traded companies in our industry, including his service as Chairman of El Paso Corporation and as its interim CEO, provides valuable experience which he can draw upon as a member of the board of our general partner.

Arthur C. Reichstetter is Director of El Paso Pipeline GP Company, L.L.C. Mr. Reichstetter has been a Director of El Paso Pipeline GP Company, L.L.C. since November 2007. He has been a private investment manager since 2007. Mr. Reichstetter served as Managing Director of Lazard Freres from April 2002 until his retirement in June 2007. From February 1998 to January 2002, Mr. Reichstetter was a Managing Director with Dresdner Kleinwort Wasserstein, formerly Wasserstein Parella & Co. Mr. Reichstetter was a Managing Director with Merrill Lynch from March 1993 until his retirement in February 1996. Prior to that time, Mr. Reichstetter worked as an investment banker at The First Boston Corporation from 1974 until 1993, in various positions becoming a managing director with that company in 1982. Mr. Reichstetter brings to the board of our general partner extensive experience in investment management and capital markets, as highlighted by his years of service at Lazard Freres, Dresdner Klienwort Wasserstein and Merrill Lynch. His leadership, together with technical expertise and extensive financial acumen provide the board with the strategic insight and experience necessary to effectuate the growth objectives of the partnership.

William A. Smith is Director of El Paso Pipeline GP Company, L.L.C. Mr. Smith has been a Director of El Paso Pipeline GP Company, L.L.C. since May 2008. From 2003 until his retirement as an active partner in 2012, Mr. Smith was a partner in Galway Group, L.P., an investment banking/energy advisory firm headquartered in Houston, Texas. In 2002, Mr. Smith retired from El Paso Corporation, where he was an Executive Vice President and Chairman of El Paso Merchant Energy's Global Gas Group. Mr. Smith had a 29 year career with Sonat Inc. prior to its merger with El Paso in 1999. At the time of the merger, Mr. Smith was Executive Vice President and General Counsel. He previously served as Chairman and President of Southern Natural Gas Company and as Vice Chairman of Sonat Exploration Company. Mr. Smith is currently a director of Eagle Rock Energy G&P LLC, a midstream/upstream master limited partnership and serves as lead director, and as chairman of that company's compensation committee. Mr. Smith previously served on the Board of Directors of Maritrans Inc. until 2006. With over 40 years of experience in the energy industry, Mr. Smith brings to the board of our general partner a wealth of knowledge and understanding of our industry, including valuable legal and business expertise. His experience as an executive and attorney provides the board with an important skill set and perspective. In addition, his experience on the board of directors of other domestic and international energy companies further augments his knowledge and experience.

Kimberly A. Dang is Vice President of El Paso Pipeline GP Company, L.L.C. and Vice President and Chief Financial Officer of KMR, Kinder Morgan G.P., Inc., and KMI. Mrs. Dang was elected Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and KMI in May 2005. She was elected Vice President, Investor Relations of KMR, Kinder Morgan G.P., Inc. and KMI in July 2002 and served in that role until January 2009. She also served as Chief Financial Officer of Kinder Morgan Holdco LLC from May 2007 until February 2011, and continued in the role of Vice President and Chief Financial Officer of KMI upon its conversion. She has served in various management roles for the Kinder Morgan companies since 2001. From May 2012 until March 2013, she also served as Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. Mrs. Dang received a Masters in Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University and a Bachelor of Business Administration degree in accounting from Texas A&M University.

David R. DeVeau is Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. DeVeau was elected Vice President and General Counsel in January 2013, such election was effective in March 2013. Mr. DeVeau joined Kinder Morgan in 2001 and has served as Deputy General Counsel from 2006 to 2013. Mr. DeVeau received his Juris Doctor from The Dickinson School of Law, Pennsylvania State University, and a bachelor's degree, cum laude, in political science from Norwich University.

David P. Michels is Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. and Vice President of Finance and Investor Relations of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. Michels was elected Chief Financial Officer and Vice President, Finance and Investor Relations in January 2013, such election was effective in March 2013. Mr. Michels joined Kinder Morgan in 2012 as Vice President, Finance/Accounting. Prior to joining Kinder Morgan, he spent six years in energy investment banking at Barclays and Lehman Brothers. While at Barclays and Lehman Brothers, he provided advisory and valuation services to clients in support of mergers and acquisitions and capital markets transactions. Mr. Michels holds a master's degree from the University of Chicago Booth School of Business and a bachelor's degree in finance from the University of Texas at Austin.

Dax A. Sanders is Vice President, Corporate Development of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. Sanders was elected Vice President, Corporate Development in January 2013, such election was effective in March 2013. Mr. Sanders also served as a Vice President within Kinder Morgan's Corporate Development group, where he served from 2009 until 2013. From 2006 until 2009, Mr. Sanders was Vice President of Finance for Kinder Morgan Canada. Mr. Sanders joined Kinder Morgan in 2000, and from 2000 to 2006 served in various finance and business development roles within the Corporate Development, Investor Relations, Gas and Products groups, with the exception of a two-year period while he attended business school. Mr. Sanders holds a master's degree in business administration from the Harvard Business School and a master's and a bachelor's degree in accounting from Texas A&M University. He is also a Certified Public Accountant in the State of Texas.

Lisa Shorb is Vice President, Human Resources, Information Technology and Administration of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. She was elected Vice President, Human Resources Information Technology and Administration of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P.,Inc. in January 2014. Ms. Shorb has served as Vice President of Procurement and Administration for the Kinder Morgan companies since June 2002. Ms. Shorb joined Kinder Morgan over 29 years ago and prior to 2002 served in various roles in the commercial and gas measurement areas. Ms. Shorb received a Masters of Science degree in Geology from Duke University and a Bachelor of Science degree in Geology from the University of Dayton.

Corporate Governance

We have a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 comprised of Messrs. Kuehn, Reichstetter and Smith. Mr. Reichstetter is the chairman of the audit committee and has been determined by the board to be an “audit committee financial expert.” The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

We have not, nor has our general partner made, within the preceding three years, contributions to any tax-exempt organization in which any of our independent directors serves as an executive officer that in any single fiscal year exceeded the greater of $1 million or 2% of such tax-exempt organization's consolidated gross revenues.

We make available free of charge within the “Investors” information section of our website, at www.kindermorgan.com, the governance guidelines, the charter of the audit committee and our code of business conduct and ethics (which applies to senior financial and accounting officers and the chief executive officer, among others). We intend to disclose any amendments to our code of business conduct and ethics that would otherwise be disclosed on Form 8-K and any waiver from a provision of that code granted to our executive officers or directors that would otherwise be disclosed on Form 8-K on our website within four business days following such amendment or waiver. The information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Interested parties may contact our lead director (Ronald L. Kuehn, Jr. **)**, discussed in Item 13, the chairpersons of any of the board's committees, the independent directors as a group or the full board by mail to El Paso Pipeline GP Company, L.L.C., 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the “Contact Us” section of our website, at www.kindermorgan.com. Any communication should specify the intended recipient.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and directors of our general partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely upon our review of the copies of such forms furnished to us and written representations from executive officers and directors of our general partner, we believe that all such filing requirements were met during 2013.

Item 11. *Executive Compensation*.

As is commonly the case for publicly traded limited partnerships, we have no officers. Under our limited partnership agreement, El Paso Pipeline G.P. Company, L.L.C., as our general partner directs, controls and manages all of our activities.

The executive officers of our general partner are also executive officers of KMI, KMR and/or Kinder Morgan G.P., Inc. The compensation of the executive officers of our general partner is set by the compensation committee of KMI, taking into consideration compensation approved by KMR's compensation committee for such persons also serving as officers of KMR. We have no control over the compensation determination process. The officers of our general partner participate in employee benefit plans and arrangements sponsored by KMI. Other than the Long-Term Incentive Plan described below, neither we nor our general partner has established any employee benefit plans and our general partner has not entered into employment agreements with any of its officers.

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by our general partner, El Paso Pipeline GP Company, L.L.C., the executive officers of which are employees of KMI. El Paso Pipeline GP Company, L.L.C. operates under an omnibus agreement with El Paso, a wholly-owned subsidiary of KMI, pursuant to which, among other matters:

- KMI makes available to El Paso Pipeline GP Company, L.L.C. the services of the KMI employees who serve as the executive officers of El Paso Pipeline GP Company, L.L.C.; and

- El Paso Pipeline GP Company, L.L.C. is obligated to reimburse KMI for any allocated portion of the costs that it incurs in providing compensation and benefits to such KMI employees.

Although we bear an allocated portion of KMI's costs of providing compensation and benefits to its employees who serve as the executive officers of our general partner, we have no control over such costs and cannot establish or direct the compensation policies or practices of KMI. Each of these executive officers performs services for our general partner, as well as KMI and its affiliates, including KMR, KMP and Kinder Morgan G.P., Inc.

We bore substantially less than a majority of KMI's costs of providing compensation and benefits to the Chief Executive Officer of our general partner (the principal executive officer) and the Chief Financial Officer of our general partner (the principal financial officer) during 2013.

Our general partner has adopted the El Paso Pipeline GP Company, L.L.C. Long-Term Incentive Plan, or *LTIP*, under which equity awards of our partnership may be granted. At this point in time, we do not anticipate that the officers of our general partner (including those that also serve as directors of the general partner) or employees of KMI will receive any grants under the LTIP. As indicated above, the compensation of such officers and employees is made pursuant to KMI's incentive plans and reimbursed by us pursuant to the omnibus agreement. Non-employee directors of our general partner receive equity grants under the LTIP, as described below.

Long-Term Incentive Plan

The LTIP was designed to promote the interests of our partnership by providing to any employees, consultants, and directors of our general partner and employees and consultants of its affiliates who perform services for us or on our behalf incentive compensation awards for superior performance that are based on our common units. Any employees, directors, and consultants of our general partner or an affiliate who perform services for us and who are selected from time to time by the board of our general partner may be granted awards under the LTIP.

The LTIP is administered by the board of our general partner or a committee thereof. The board of our general partner, subject to the terms of the LTIP, has authority to (i) select the persons to whom awards are to be granted, (ii) determine the size and type of awards, (iii) determine the terms and conditions of any award, including any performance conditions, (iv) determine whether, to what extent, and under what circumstances awards may be settled, exercised, canceled, or forfeited; (vi) interpret and administer the LTIP and any instrument or agreement relating to an award made under the LTIP; (vii) establish, amend, suspend, or waive such rules and regulations and appoint such agents as it shall deem appropriate for the proper administration of the LTIP; and (viii) make any other determination and take any other action that the board of our general partner deems necessary or desirable for the administration of the LTIP. All decisions, interpretations and other actions of the board of our general partner are final and binding.

The LTIP authorizes the granting of unit options, restricted common units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The maximum number of our common units that may at any time be delivered or reserved for delivery under the LTIP is 1,250,000 common units. If any award expires, is canceled, exercised, paid or otherwise terminates without the delivery of common units, then the units covered by such award shall again be units with respect to which awards may be granted.

The board of our general partner may terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. The board of our general partner also has the right to alter or amend the LTIP or any part thereof from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The LTIP will expire on the earliest of (i) the date common units are no longer available under the LTIP for grants, (ii) termination of the LTIP by the board of our general partner or (iii) the date 10 years following its date of adoption.

Compensation of Directors

Officers or employees of KMI or its affiliates who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Directors who are not officers or employees of KMI or its affiliates, referred to in this report as non-employee directors, are compensated for their services on the board, as described below. In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees thereof. Each director is fully indemnified by us for his or her actions associated with being a director to the fullest extent permitted under Delaware law pursuant to a director indemnification agreement and our partnership agreement.

Cash Retainer

Each non-employee director of our general partner receives an annual cash retainer paid in quarterly installments. For 2013, the annual cash retainer was $65,000. In addition, the chairman of the audit committee receives an additional retainer of $8,000 per year. In January 2014, the annual cash retainer was increased to $85,000.

Initial Equity Grant

Each non-employee director, upon joining the board, receives an initial long-term equity grant of restricted common units having a fair value of $60,000. The restricted common units are granted pursuant to the terms and conditions of the LTIP and vest in three (3) equal installments commencing on the last day of the calendar year of the year in which the grant was made and each of the following two anniversaries thereof. As no non-employee directors joined the board during 2013, no initial equity grants were made in 2013.

Annual Equity Grant

Each non-employee director who is serving on the board on December 1st receives an annual grant of restricted common units with a value of $60,000. This annual award is granted pursuant to the terms and conditions of the LTIP and vests in full on the last day of the calendar year following the year in which the grant was made. Annual equity grants for Messrs. Kuehn, Reichstetter and Smith were made on December 2, 2013.

Director Compensation

Non-employee directors do not receive stock options or pension benefits. The following table sets forth the aggregate dollar amount of all fees paid to each of the non-employee directors of our general partner during 2013 for their services on the board:

Director Compensation
for the Year Ended December 31, 2013

Name(a)	Fees Earned or Paid in Cash(b)	Stock Awards(c)(d)	All Other Compensation(e)	Total
Ronald L. Kuehn, Jr.	$ 65,000	$ 60,009	$ 4,036	$ 129,045
Arthur C. Reichstetter	73,000	60,009	4,036	137,045
William A. Smith	65,000	60,009	4,036	129,045

(a) Amounts paid as reimbursable business expenses to each director for attending board functions are not reflected in this table. Our general partner does not consider the directors' reimbursable business expenses for attending board functions and other business expenses required to perform board duties to have a personal benefit and thus be considered a perquisite.

(b) This column reflects the value of a director's annual retainer, as well as the additional retainer for the chairman of the audit committee.

(c) The amount in this column represents the aggregate grant date fair value of restricted units granted in the fiscal year calculated in accordance with FASB Accounting Standards Codification Topic 718, "Compensation - Stock Compensation." Each of Messrs. Kuehn, Reichstetter and Smith received a grant of 1,453 restricted common units on December 2, 2013 pursuant to the Long-Term Incentive Plan, with each unit having a grant date fair value of $41.30.

(d) As of December 31, 2013, each of Messrs. Kuehn, Reichstetter and Smith had 1,453 restricted common units outstanding.

(e) The amount in this column for Messrs. Kuehn, Reichstetter and Smith represent cash distributions received on unvested restricted common units.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* .

The following table sets forth information as of January 31, 2014, regarding (i) the beneficial ownership of our common units by all directors of our general partner, by the principal executive officer, principal financial officer and three other most highly compensated executive officers of our general partner (referred to in this report as the named executive officers of our general partner) and by all directors and executive officers as a group; and (ii) the beneficial ownership of our common units by all persons known by our general partner to own beneficially at least 5% of such units or shares. Unless otherwise noted, the address of each person below is c/o El Paso Pipeline Partners L.P., 1001 Louisiana Street, Suite 1000, Houston, Texas 77002.

Amount and Nature of Beneficial Ownership(a)

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned(b)
Richard D. Kinder	28,000	*
Steven J. Kean	18,000	*
Thomas A. Martin	—	—
Ronald L. Kuehn, Jr.	78,121	*
Arthur C. Reichstetter	113,753	*
William A. Smith	13,858	*
Kimberly A. Dang	—	—
David P. Michels	—	—
Directors and Executive Officers as a group (11 persons)	251,732	*
Kinder Morgan Inc.(c)	90,320,810	41.46%

* Less than 1%.

(a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the units and shares listed.

(b) The percentage of total units to be beneficially owned is based on 217,831,642 common units outstanding as of January 31, 2014.

(c) Includes 90,320,810 common units held by El Paso Pipeline LP Holdings, L.L.C., KMI's wholly-owned subsidiary. KMI also indirectly owns our general partner, which holds a 2% general partner interest in us and the incentive distribution rights.

The following table sets forth information as of January 31, 2014, regarding the beneficial ownership of KMI Class P shares by each of the named executive officers and directors of our general partner and by all directors and executive officers of our general partner as a group.

Amount and Nature of Beneficial Ownership(a)

	KMI Class P Shares	
Name of Beneficial owner	**Number of Shares**	**Percent of Class P Shares(b)**
Richard D. Kinder(c)	242,700,835	23.55%
Steven J. Kean(d)	8,074,560	*
Thomas A. Martin(e)	1,110,240	*
Ronald L. Kuehn, Jr.(f)	52,675	*
Arthur C. Reichstetter	—	—
William A. Smith(g)	3,622	*
Kimberly A. Dang(h)	2,336,914	*
David P. Michels	19,768	*
Directors and officers as a group (11 persons)(i)	255,153,146	24.76%

* Less than 1%.

(a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the shares listed.

(b) The percentage of total class P shares beneficially owned is based on 1,030,677,290 Class P shares issued and outstanding as of January 31, 2014.

(c) Includes 40,467 Class P shares owned by Mr. Kinder's wife. Mr. Kinder disclaims any and all beneficial or pecuniary interest in the Class P shares held by his wife. Also includes 11,072,258 Class P shares held by a limited partnership of which Mr. Kinder controls the voting and disposition power. Mr. Kinder disclaims 99% of any beneficial and pecuniary interest in these shares.

(d) Includes 230,000 Class P shares held by a limited partnership. Mr. Kean is the sole general partner of the limited partnership, and two trusts of which family members of Mr. Kean are sole beneficiaries and Mr. Kean is a trustee, each own a 49.5% limited partner interest in the limited partnership. Mr. Kean disclaims beneficial ownership of the Class P shares held by the limited partnership except to the extent of his pecuniary interest therein. Also includes 625,000 Class P shares owned by a charitable foundation of which Mr. Kean is a member of the board of directors and shares voting and investment power. Mr. Kean disclaims any beneficial ownership in these 625,000 shares.

(e) Includes 148,950 Class P shares held by a trust for the benefit of family members of Mr. Martin with respect to which Mr. Martin shares voting and disposition power. Mr. Martin disclaims any beneficial ownership in these shares.

(f) Includes 10,365 Class P shares owned by Mr. Kuehn's spouse or children. Mr. Kuehn disclaims beneficial ownership of such shares. Amount does not reflect warrants to purchase 64,000 Class P shares held by Mr. Kuehn, which warrants are not currently exercisable based on current market prices for the Class P shares.

(g) Includes 3,622 Class P shares held by Mr. Smith's wife. Mr. Smith disclaims beneficial ownership of these shares. Amount does not reflect warrants to purchase 5,479 Class P Shares held by Mr. Smith's wife, which warrants are not currently exercisable based on current market prices for the Class P shares. Mr. Smith disclaims beneficial ownership of these warrants.

(h) Includes 2,026,048 Class P shares held by a limited partnership of which Mrs. Dang controls the voting and disposition power. Mrs. Dang disclaims 10% of any beneficial and pecuniary interests in these shares. Amount does not include warrants to purchase 192 Class P shares held by Mrs. Dang, which warrants are not currently exercisable based on current market prices for the Class P shares.

(i) See notes (c) through (h) above. Also includes 174,019 Class P shares held by limited partnerships, limited liability companies or trusts with respect to which executive officers have sole or shared voting or disposition power, but in respect of which Class P shares, the executive officers disclaim all or a portion of any beneficial or pecuniary interest. Amount does not include warrants to purchase 1,600 Class P shares held by an executive officer, which warrants are not currently exercisable based on current market prices for the Class P shares.

EQUITY COMPENSATION PLAN INFORMATION TABLE

The following table provides information concerning securities that may be issued under the El Paso Pipeline GP Company, L.L.C. Long-Term Incentive Plan as of December 31, 2013. For more information regarding this plan, which did not require approval by our limited partners, please read "Executive Compensation - Long-Term Incentive Plan."

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by unitholders	—	$ —	—
Equity compensation plans not approved by unitholders (a)	—	—	1,207,932
Total	—	$ —	1,207,932

(a) Please read "Executive Compensation — Long-Term Incentive Plan" for a description of the material features of the plan, including the awards that may be granted under the plan.

Item 13. *Certain Relationships and Related Transactions and Director Independence .*

KMI owns 90,320,810 common units, a 41% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and all of our IDRs.

Related Transactions

Our policy is that (i) employees must obtain authorization from the appropriate business unit president of the relevant company or head of corporate function, and (ii) directors, business unit presidents, executive officers and heads of corporate functions must obtain authorization from the non-interested members of the audit committee of the applicable board of directors, for any business relationship or proposed business transaction in which they or an immediate family member has a direct or indirect interest, or from which they or an immediate family member may derive a personal benefit (a “related party transaction”). When deciding whether to authorize a related party transaction, our business unit presidents and the non-interested members of the audit committee of the applicable board of directors, consider, among other things, the nature of the transaction and the relationship, the dollar amount involved, and the availability of reasonable alternatives.

The maximum dollar amount of related party transactions that may be approved as described above in this paragraph in any calendar year is $1.0 million. Any related party transactions that would bring the total value of such transactions to greater than $1.0 million must be referred to the audit committee of the appropriate board of directors for approval or to determine the procedure for approval.

For further information regarding our related party transactions, see Note 8 to our consolidated financial statements.

Reimbursement of Operating and General and Administrative Expense

Under the omnibus agreement and other policies, we reimburse KMI and its affiliates without a profit component for the payment of certain operating expenses and for the provision of various operating expenses and general and administrative services for our benefit with respect to the assets contributed to us. The agreements further provide that we reimburse KMI without a profit component for our allocable portion of the premiums on insurance policies covering our assets.

Pursuant to these arrangements, KMI performs centralized corporate functions for us, such as legal, accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. We reimburse KMI and its affiliates without a profit component for our allocable portion of the expenses.

Contracts with Affiliates

Operating and Services Agreements

On June 30, 1992, CIG entered into a Construction and Operating Agreement with Young, a limited partnership in which KMI indirectly owns a general partner interest. This agreement was amended in 1994 and 1997. Under this agreement, CIG agreed to design and construct the Young storage facilities and to operate the facilities (including conducting Young's marketing and administering Young's service agreements) using the same practices that CIG adopts in the operation and administration of its own facilities. CIG is entitled to reimbursement of all costs incurred in the performance of the services, including both direct costs and allocations of general and administrative costs based on direct field labor charges (including any costs charged or allocated to CIG from other affiliates). The agreement is subject to termination only in the event of the dissolution or bankruptcy of CIG, or a material default by CIG that is not cured within certain permissible time periods. Otherwise, the agreement continues until the termination of the Young partnership agreement.

On January 25, 2013, SLNG entered into a Maintenance, Administrative and Operating Agreement with ELC, a limited liability company in which SLC is a 51% member. Under the agreement, SLNG agreed to perform operation, maintenance and administrate services associated with the construction and operation of liquefaction facilities at SLNG's Elba Island LNG terminal. SLNG is entitled to reimbursement of all costs incurred in the performance of the services. This agreement is for a primary term of 20 years from the in-service date of the last liquefaction unit to be placed in service pursuant to the underlying service agreement. The agreement can be terminated in the event of default by SLNG that is not cured within certain permissible time periods.

Transportation Agreements

CIG is a party to a capacity release agreement with PSCo, whereby PSCo has released storage capacity in our affiliate, Young, to us for a term expiring on April 30, 2025. PSCo simultaneously contracted for a corresponding quantity of transportation and storage balancing service (which utilizes the storage capacity acquired through the capacity release).

Interconnection and Operational Balancing Agreements and Other Inter-Affiliate Agreements

CIG is a party to interconnection and operational balancing agreements with Ruby, of which KMI indirectly owns a 50% equity interest. These agreements require the interconnecting parties to use their respective reasonable efforts to cause the quantities of gas that are tendered/accepted at each point of interconnection to equal the quantities scheduled at those points. The agreements provide for the treatment and resolution of imbalances. The agreements are terminable by either party on 30 days advance notice.

WIC is a party to an “Upstream Pipeline Capacity Agreement” with Ruby. Pursuant to this agreement, WIC agreed to offer gas transportation services to shippers desiring to move gas volumes to the inlet of the proposed Ruby pipeline at Opal, Wyoming. Ruby has agreed to reimburse WIC for any unrecovered costs associated with 80 MDth/d of off-system capacity that was acquired by WIC to provide the upstream transportation services (either through a direct payment or through the acquisition of capacity on WIC). The off-system capacity was acquired by WIC on the expansions of the Rockies Express Pipeline from the Piceance Basin to Wamsutter, and the expansion of the Overthrust Pipeline from Wamsutter to Opal.

Other Agreements

In addition, each of WIC, CIG, SLNG, Elba Express, CPG and SNG currently have or will have in the future other routine agreements with KMI and its affiliates that arise in the ordinary course of business, including revised and updated agreements for services and other transportation and exchange agreements and interconnection and balancing agreements with other KMI pipelines.

For a description of certain additional affiliate transactions, see Note 8 to our consolidated financial statements.

Director Independence

The board has adopted governance guidelines for the board and a charter for the audit committee. The governance guidelines and the rules of the NYSE include standards for director independence. As a limited partnership and a "controlled company" (as that term is defined in the rules of the NYSE), we and our general partner are not required to have a majority of independent directors. Copies of the guidelines and the audit committee charter are available on our Internet website at www.kindermorgan.com.

The board has affirmatively determined that Ronald L. Kuehn, Jr., Arthur C. Reichstetter and William A. Smith are independent as described in our governance guidelines and the NYSE. In conjunction with all regular quarterly and certain special board meetings, these three non-employee directors also meet in executive session without members of management. In January 2014, Mr. Kuehn was elected for a one year term to serve as lead director to develop the agendas for and preside at these executive sessions of independent directors.

The governance guidelines and our audit committee charter, as well as the rules of the NYSE and the SEC, require that members of the audit committee satisfy independence requirements in addition to those above. The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

Item 14. *Principal Accounting Fees and Services.*

In connection with the KMI's acquisition of El Paso, the audit committee of our general partner approved the engagement of PricewaterhouseCoopers LLP (“PwC”) to audit our consolidated financial statements for the year ended December 31, 2013. PwC replaced Ernst & Young (“E&Y”), which was dismissed as our independent auditor effective May 25, 2012. PwC is KMI's and subsidiaries' independent auditor; therefore PwC has become our independent auditor.

In connection with the reviews of interim periods through May 24, 2012, there were no disagreements between us and E&Y on any matters of accounting principles or practices, financial statement disclosure, auditing scope or procedures which, if not resolved to the satisfaction of E&Y, would have caused E&Y to make reference to the matter in its reports.

We did not consult with PwC during the interim periods through May 24, 2012.

	PricewaterhouseCoopers LLP		Ernst & Young	
	2013	2012	2013	2012
Audit fees(a)	$ 1,804,000	$ 2,297,000	$ 34,000	$ 480,000
Tax fees(b)	896,000	478,000	—	235,000
Audit-related fees	—	—	—	—
All other fees	—	—	—	—
Total	$ 2,700,000	$ 2,775,000	$ 34,000	$ 715,000

(a) Includes fees for the integrated audit of annual financial statements and internal control over financial reporting, reviews of the related quarterly financial statements and reviews of documents filed with the SEC.
(b) Includes fees for professional services rendered for tax processing and preparation of Forms K-1 for our unitholders.

All services rendered by PWC and E&Y are permissible under applicable laws and regulations, and were pre-approved by the audit committee of our general partner. Pursuant to the charter of the audit committee, the committee's primary purposes include the following: (i) to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; (ii) to pre-approve all audit and non-audit services, including tax services, to be provided, consistent with all applicable laws, to us by our external auditors; and (iii) to establish the fees and other compensation to be paid to our external auditors. The audit committee has reviewed the external auditors' fees for audit and non-audit services for fiscal year 2013. The audit committee has also considered whether such non audit services are compatible with maintaining the external auditors' independence and has concluded that they are compatible at this time.

Furthermore, the audit committee will review the external auditors' proposed audit scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, will regularly review with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and will, at least annually, use its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items): (i) the auditors' internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors; (iii) the independence of the external auditors; and (iv) the aggregate fees billed by our external auditors for each of the previous two fiscal years.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*.

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Financial Statements" set forth on page 63.

(3) Exhibits

Exhibit Number	Description
2.1*	Contribution Agreement dated March 24, 2010 by and among El Paso Corporation, El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the SEC on March 25, 2010).
2.2*	Contribution Agreement dated June 17, 2010, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the SEC on June 22, 2010).
2.3*	Contribution Agreement, dated May 17, 2012, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso LLC, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, L.L.C., El Paso CNG Company, L.L.C., El Paso Cheyenne Holdings, L.L.C., Cheyenne Plains Investment Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C. and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the SEC on May 21, 2012).
3.1*	Certificate of Limited Partnership of El Paso Pipeline Partners, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-145835) filed with the SEC on August 31, 2007).
3.2*	First Amended and Restated Agreement of Limited Partnership of El Paso Pipeline Partners, L.P., dated November 21, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed with the SEC on November 28, 2007); Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of El Paso Pipeline Partners, L.P., dated July 28, 2008 (incorporated by reference to Exhibit 4.A to our Current Report on Form 8-K, filed with the SEC on July 28, 2008); Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of El Paso Pipeline Partners, L.P., dated November 14, 2013 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed with the SEC on November 15, 2013).
3.3*	Certificate of Formation of El Paso Pipeline GP Company, L.L.C. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 (File No. 333-145835) filed with the SEC on August 31, 2007).
3.4*	Amended and Restated Limited Liability Company Agreement of El Paso Pipeline GP Company, L.L.C., dated November 21, 2007 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).

Exhibit Number	Description
4.1*	Indenture dated June 1, 1987 between Southern Natural Gas Company and Wilmington Trust Company (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.A to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); First Supplemental Indenture, dated as of September 30, 1997, between Southern Natural Gas Company and the Trustee (Exhibit 4.A.1 to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); Second Supplemental Indenture dated as of February 13, 2001, between Southern Natural Gas Company and the Trustee (Exhibit 4.A.2 to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); Third Supplemental Indenture dated as of March 26, 2007 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on March 28, 2007); Fourth Supplemental Indenture dated as of May 4, 2007 among Southern Natural Gas Company, Wilmington Trust Company (solely with respect to certain portions thereof) and The Bank of New York Trust Company, N.A. (Exhibit 4.C to the Southern Natural Gas Company quarterly report on Form 10-Q for the period ended March 31, 2007, filed with the SEC on May 8, 2007); Fifth Supplemental Indenture dated October 15, 2007 by and among SNG, Wilmington Trust Company, as trustee, and The Bank of New York Trust Company, N.A., as series trustee, to Indenture dated as of June 1, 1987 (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on October 16, 2007); Sixth Supplemental Indenture dated November 1, 2007 by and among Southern Natural Gas Company, Southern Natural Issuing Corporation, Wilmington Trust Company, as trustee, and The Bank of New York Trust Company, N.A., as series trustee, to Indenture dated as of June 1, 1987 (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on November 7, 2007); Seventh Supplemental Indenture dated as of June 7, 2011, among the Issuers and Wilmington Trust Company, as trustee (including the form of 4.40% Note due 2021) (incorporated by reference to Exhibit 4.1 to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on June 9, 2011).
4.2*	Form of 5.90% Note due 2017 (included as Exhibit A to Exhibit 4.A of the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on March 28, 2007).
4.3*	Indenture dated as of March 5, 2003 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., successor to The Bank of New York, as Trustee (Exhibit 4.C to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
4.4*	Indenture dated as of June 27, 1997, between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A. (successor to Harris Trust and Savings Bank), as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); First Supplemental Indenture dated as of June 27, 1997, between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.1 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Second Supplemental Indenture dated as of March 9, 2005 between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.2 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Third Supplemental Indenture dated as of November 1, 2005 between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.3 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Fourth Supplemental Indenture dated October 15, 2007 by and between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Current Report on Form 8-K filed with the SEC on October 16, 2007); Fifth Supplemental Indenture dated November 1, 2007 by and among Colorado Interstate Gas Company, Colorado Interstate Issuing Corporation, and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Current Report on Form 8-K filed with the SEC on November 7, 2007).
4.5*	Indenture, dated March 30, 2010, between El Paso Pipeline Partners Operating Company, L.L.C. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).
4.6*	First Supplemental Indenture, dated March 30, 2010, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).

Exhibit Number	Description
4.7*	Second Supplemental Indenture, dated November 19, 2010, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
4.8*	Third Supplemental Indenture, dated as of September 20, 2011, by and among El Paso Pipeline Partners Operating Company, L.L.C, El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on September 21, 2011).
4.9*	Fourth Supplemental Indenture, dated November 8, 2012, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed with the SEC on November 15, 2012).
10.1*	Credit Agreement dated as of May 27, 2011, among El Paso Pipeline Partners Operating Company, L.L.C. and Wyoming Interstate Company, L.L.C., as borrowers, El Paso Pipeline Partners, L.P., as parent guarantor, and the lenders and agents identified therein (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.2*	Omnibus Agreement, dated November 21, 2007, among El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Colorado Interstate Gas Company, Southern Natural Gas Company and El Paso Corporation (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).
10.3*	Long-Term Incentive Plan of El Paso Pipeline GP Company, L.L.C. (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).
10.4*	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.20 to our Registration Statement on Form S-1).
10.5*	Form of Master Services Agreement by and between Colorado Interstate Gas Company and El Paso Corporation, Tennessee Gas Pipeline Company, El Paso Natural Gas Company and CIG Pipeline Services Company L.L.C. (incorporated by reference to Exhibit 10.21 to our Registration Statement on Form S-1).
10.6*	Form of Master Services Agreement by and between Southern Natural Gas Company and El Paso Corporation, Tennessee Gas Pipeline Company and SNG Pipeline Services Company, L.L.C. (incorporated by reference to Exhibit 10.22 to our Registration Statement on Form S-1).
10.7*	Note Purchase Agreement, dated September 30, 2008, by and among El Paso Pipeline Partners, L.P., as guarantor, El Paso Pipeline Partners Operating Company, L.L.C., as issuer, and the insurance companies and financial institutions named therein as parties thereto (incorporated by reference to Exhibit 10.M to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
10.8*	Lease Agreement dated December 17, 2008, and effective on November 1, 2008, by and between WYCO Development LLC, a Colorado limited liability company, and Colorado Interstate Gas Company, a Delaware corporation (Exhibit 10.C to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
10.9*	Contribution, Conveyance and Assumption Agreement by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline Holdings, L.L.C., El Paso Pipeline GP Company, L.L.C. and El Paso Corporation (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).
10.10*	Second Amended and Restated Limited Liability Company Agreement of Southern LNG Company, L.L.C. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
10.11*	Firm Transportation Service Agreement under Rate Schedule FTS, dated October 5, 2007, between Elba Express Company and Shell NA LNG LLC (incorporated by reference to Exhibit 10.A of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).

Exhibit Number	Description
10.12*	Guaranty dated April 1, 2010, by Shell Oil Company, in favor of Elba Express Company, L.L.C. (incorporated by reference to Exhibit 10.B of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.13*	Service Agreement under Rate Schedule LNG-3 dated October 5, 2007, between Southern LNG Inc. and Shell NA LNG LLC (incorporated by reference to Exhibit 10.C of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.14*	Guaranty dated April 1, 2010, by Shell Oil Company, in favor of Southern LNG Company, L.L.C. (incorporated by reference to Exhibit 10.D of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.15*	Contribution Agreement dated November 12, 2010 by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Corporation, El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., Southern Natural Gas Company, El Paso SNG Holding Company, L.L.C. and EPPP SNG GP Holdings, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
10.16*	Contribution Agreement dated March 4, 2011 by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Corporation, Southern Natural Gas Company, El Paso SNG Holding Company, L.L.C. and EPPP SNG GP Holdings, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on March 17, 2011).
10.17*	Contribution, Conveyance and Assumption Agreement by and among El Paso Pipeline Partners, L.P. El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed with the SEC on March 17, 2011).
10.18*	Contribution Agreement dated June 29, 2011, by and among El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, EPPP CIG GP Holdings, L.L.C., El Paso Pipeline Partners, L.P., and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on July 6, 2011).
10.19*	Contribution, Conveyance and Assumption Agreement dated June 29, 2011, by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, El Paso Noric Investments III, L.L.C., EPPP CIG GP Holdings, L.L.C., El Paso CNG Company. L.L.C. and El Paso Corporation (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed with the SEC on July 6, 2011).
10.20*	Purchase Agreement, dated as of June 2, 2011, among the Issuers, EPP SNG GP Holdings L.L.C., El Paso SNG Holding Company, L.L.C. and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on June 9, 2011).
10.21*	Contribution, Conveyance and Assumption Agreement, dated May 24, 2012, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso LLC, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, L.L.C., El Paso CNG Company, L.L.C., El Paso Cheyenne Holdings, L.L.C., Cheyenne Plains Investment Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C. and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on May 24, 2012).
10.22*^	Limited Liability Company Agreement of Elba Liquefaction Company, L.L.C. (incorporated by reference to our Amendment No. 1 to Quarterly Report on Form 10-Q for the period ended March 31, 2013 filed with the SEC on August 16, 2013).
10.23*^	Liquefaction Services Agreement by and between Elba Liquefaction Company, L.L.C. and Shell NA LNG, LLC, dated January 25, 2013 (incorporated by reference to our Amendment No. 1 to Quarterly Report on Form 10-Q for the period ended March 31, 2013 filed with the SEC on August 16, 2013).
12	Ratio of Earnings to Fixed Charges
21	List of subsidiaries of El Paso Pipeline Partners, L.P.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Ernst & Young LLP.

Exhibit Number	Description
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011; (iii) our Consolidated Balance Sheets as of December 31, 2013 and 2012; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011; (v) our Consolidated Statements of Partners' Capital as of and for the years ended December 31, 2013, 2012 and 2011; and (vi) the notes to our Consolidated Financial Statements.

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

^ Caret indicates certain confidential information has been omitted from this exhibit and filed separately with the SEC pursuant to a confidential treatment request.

EL PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of El Paso Pipeline Partners, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of El Paso Pipeline Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing in Item 9A of the Partnership's 2013 Annual Report on Form 10-K. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 19, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors of El Paso Pipeline GP Company, L.L.C.
as General Partner of El Paso Pipeline Partners, L.P.,
and the Partners of El Paso Pipeline Partners, L.P.:

We have audited the consolidated balance sheet of El Paso Pipeline Partners, L.P. (the Partnership) as of December 31, 2011 (not presented separately herein), and the related consolidated statements of income, comprehensive income, partners' capital and cash flows for the year ended December 31, 2011. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of El Paso Pipeline Partners, L.P. at December 31, 2011 (not presented separately herein), and the consolidated results of its operations and its cash flows for the year ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2013

El PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(In Millions, Except Per Unit Amounts)

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 1,505	$ 1,515	$ 1,531
Operating Costs and Expenses			
Operations and maintenance	329	387	419
Depreciation and amortization	198	183	180
Taxes, other than income taxes	83	82	83
Total Operating Costs and Expenses	610	652	682
Operating Income	895	863	849
Other Income (Expense)			
Earnings from equity investments	13	14	15
Interest expense, net	(300)	(293)	(267)
Other, net	2	5	8
Total Other Income (Expense)	(285)	(274)	(244)
Net Income	610	589	605
Net Income Attributable to Noncontrolling Interests	—	(10)	(93)
Net Income Attributable to El Paso Pipeline Partners, L.P.	$ 610	$ 579	$ 512
Calculation of Limited Partners' Interest in Net Income Attributable to El Paso Pipeline Partners, L.P.:			
Net Income Attributable to El Paso Pipeline Partners, L.P.	$ 610	$ 579	$ 512
Less: Pre-acquisition Earnings Allocated to General Partner	—	(22)	(40)
Plus: Severance Costs Allocated to General Partner	1	34	—
Income Subject to 2% Allocation of General Partner Interest	$ 611	$ 591	$ 472
Less: General Partner's Interest	(12)	(12)	(9)
General Partner's Incentive Distribution	(195)	(129)	(62)
Limited Partners' Interest in Net Income	$ 404	$ 450	$ 401
Limited Partners' Net Income per Unit- Basic and Diluted	$ 1.86	$ 2.15	$ 2.03
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit- Basic and Diluted	217	209	197
Per Unit Cash Distribution Declared for the Period	$ 2.55	$ 2.25	$ 1.93

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

EL PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)

	Year Ended December 31,		
	2013	2012	2011
Net Income	$ 610	$ 589	$ 605
Other Comprehensive Income:			
Change in fair value of derivatives utilized for hedging purposes	—	(1)	(6)
Reclassification of change in fair value of derivatives to net income	—	4	7
Reclassification of terminated hedge to net income (a)	—	12	—
Adjustments to postretirement benefit plan liabilities	—	2	9
Total Other Comprehensive Income	—	17	10
Comprehensive Income	610	606	615
Comprehensive Income Attributable to Noncontrolling Interests	—	(10)	(94)
Comprehensive Income Attributable to El Paso Pipeline Partners, L.P.	$ 610	$ 596	$ 521

(a) See Note 10 for further discussion.

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

El PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In Millions, Except Units)

	December 31,	
	2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 78	$ 114
Accounts receivable, net	147	155
Inventories	34	34
Regulatory assets	26	46
Other current assets	19	6
Total current assets	304	355
Property, plant and equipment, net	5,879	5,931
Investments	87	72
Regulatory assets	120	147
Deferred charges and other assets	105	76
Total Assets	$ 6,495	$ 6,581
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 77	$ 93
Accounts payable	73	67
Accrued interest	51	53
Accrued taxes, other than income	37	31
Regulatory liabilities	17	17
Other current liabilities	22	20
Total current liabilities	277	281
Long-term liabilities and deferred credits		
Long-term debt	4,171	4,246
Other long-term liabilities and deferred credits	108	67
Total Liabilities	4,556	4,594
Commitments and contingencies (Note 9)		
Partners' Capital		
Common units (217,831,642 and 215,789,325 units issued and outstanding at December 31, 2013 and 2012)	4,197	4,253
General partner units (4,445,455 and 4,403,765 units issued and outstanding at December 31, 2013 and 2012)	(2,268)	(2,276)
Accumulated other comprehensive income	10	10
Total Partners' Capital	1,939	1,987
Total Liabilities and Partners' Capital	$ 6,495	$ 6,581

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

El PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)

	Year Ended December 31,		
	2013	**2012**	**2011**
Cash Flows From Operating Activities			
Net Income	$ 610	$ 589	$ 605
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	198	183	180
Earnings from equity investments	(13)	(14)	(15)
Distributions from equity investment earnings	11	13	15
Non-cash severance costs	1	34	—
Other non-cash items	15	22	26
Changes in components of working capital:			
Accounts receivable	7	(56)	—
Regulatory assets	23	(10)	5
Other current assets, including inventories	—	(2)	5
Accounts payable	(4)	(30)	14
Accrued interest	(2)	2	7
Accrued taxes, other than income	3	(8)	(3)
Regulatory liabilities	3	1	(17)
Other current liabilities	(2)	(23)	2
Other long-term assets and liabilities	8	15	(6)
Net Cash Provided by Operating Activities	858	716	818
Cash Flows From Investing Activities			
Capital expenditures	(125)	(109)	(255)
Contributions to equity investments	(13)	—	—
Cash paid to acquire interests in CPG	—	(185)	—
Proceeds from sale of assets	—	50	1
Other, net	(4)	(5)	(13)
Net Cash Used in Investing Activities	(142)	(249)	(267)
Cash Flows from Financing Activities			
Issuance of debt	87	1,274	1,771
Payments of debt	(180)	(1,050)	(1,318)
Net proceeds from issuance of common and general partner units	87	279	968
Cash distributions to unitholders and general partner	(746)	(564)	(422)
Cash distributions to CPG's preferred interest	—	—	(14)
Cash distributions by subsidiaries to El Paso	—	(28)	(116)
Cash contributions to subsidiaries from El Paso	—	2	34
Excess of cash paid for CPG interests over contributed book value	—	(180)	—
Cash paid to acquire additional interests in CIG and SNG	—	(206)	(1,412)
Other	—	—	(1)
Net Cash Used in Financing Activities	(752)	(473)	(510)

Net (decrease) increase in Cash and Cash Equivalents		(36)		(6)		41
Cash and Cash Equivalents, beginning of period		114		120		79
Cash and Cash Equivalents, end of period	$	78	$	114	$	120
Non-cash Investing Activities						
Increase (decrease) in property, plant and equipment accruals and contractor retainage	$	7	$	(4)	$	(25)
Supplemental Cash Flow Information						
Cash paid during the period for interest (net of capitalized interest)	$	283	$	274	$	274

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

El PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In Millions, Except Units)

	2013		2012		2011	
	Units	Amount	Units	Amount	Units	Amount
Limited partner common:						
Beginning Balance	215,789,325	$ 4,253	205,698,750	$ 3,977	149,440,452	$ 2,686
Net income		404		450		401
Conversion of subordinated units to common units		—		—	27,727,411	307
Issuance of units, net of issuance costs	2,042,317	85	8,169,824	272	28,530,887	948
Cash distributions to unitholders		(545)		(447)		(365)
Units issued to acquire interests in CIG and CPG		—	1,920,751	—		—
Other		—		1		—
Ending Balance	217,831,642	4,197	215,789,325	4,253	205,698,750	3,977
General partner:						
Beginning Balance	4,403,765	(2,276)	4,197,822	(1,855)	3,615,578	(1,525)
Net income		206		129		111
Issuance of units	41,690	2	166,744	7	582,244	20
Cash distributions to general partner		(201)		(117)		(57)
Units issued to acquire interests in CIG and CPG		—	39,199	—		—
Cash distributions by subsidiaries to El Paso		—		(15)		(37)
Cash contributions to subsidiaries from El Paso		—		—		4
Cash paid to general partner to acquire interests in CIG, CPG and SNG		—		(571)		(1,412)
Acquisition of additional interests in CIG and SNG		—		114		896
Third party preferred interest in CPG transferred to El Paso		—		—		145
Non-cash contributions from general partner		1		34		—
Other		—		(2)		—
Ending Balance	4,445,455	(2,268)	4,403,765	(2,276)	4,197,822	(1,855)
Limited partner subordinated:						
Beginning Balance		—	—	—	27,727,411	307
Conversion of subordinated units to common units		—	—	—	(27,727,411)	(307)
Ending Balance	—	—	—	—	—	—

Accumulated other comprehensive income (loss):						
Beginning Balance		10		(7)		(15)
Acquisition of remaining interest in CIG		—		1		—
Other comprehensive income		—		16		8
Ending Balance		10		10		(7)
Total EPB Partners' Capital	222,277,097	1,939	220,193,090	1,987	209,896,572	2,115
Noncontrolling interests:						
Beginning Balance		—		116		981
Net income		—		10		79
Cash distributions by subsidiaries to El Paso		—		(13)		(79)
Cash contributions to subsidiaries from El Paso		—		2		30
Acquisition of additional interests in CIG and SNG		—		(115)		(896)
Other comprehensive income		—		—		1
Ending Balance		—		—		116
Total Partners' Capital	222,277,097	$ 1,939	220,193,090	$ 1,987	209,896,572	$ 2,231

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

El PASO PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are a Delaware MLP formed in 2007 to own and operate interstate natural gas transportation and terminaling facilities. We own WIC, SLNG, Elba Express, SNG, CIG, SLC and CPG. WIC and CIG are interstate pipeline systems serving the Rocky Mountain region. CPG has an interstate pipeline which serves the Rocky Mountain and Midwest regions. SLNG owns the Elba Island LNG storage and regasification terminal near Savannah, Georgia. Elba Express and SNG are interstate pipeline systems serving the southeastern region of the U.S. Our equity method investments include WYCO, which is owned 50% by CIG, Bear Creek, which is owned 50% by SNG, and ELC, which is owned 51% by SLC. ELC was formed in January 2013 to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal. We are controlled by our general partner, El Paso Pipeline GP Company, L.L.C., an indirect wholly owned subsidiary of KMI.

2. Summary of Significant Accounting Policies

Basis of Presentation

We have prepared our accompanying consolidated financial statements under the rules and regulations of the SEC. These rules and regulations conform to the accounting principles contained in the FASB's Accounting Standards Codification, the single source of GAAP and referred to in this report as the Codification. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Additionally, our financial statements are consolidated into the consolidated financial statements of KMI. Also, except for the related party transactions described in Note 8, KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In addition, we believe that certain accounting policies are of more significance in our financial statement preparation process than others. Below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

Accounts Receivable

The amounts reported as “Accounts receivable, net” on our accompanying Consolidated Balance Sheets at December 31, 2013 and 2012 primarily consist of amounts due from third party payors (unrelated entities). For information on receivables due to us from related parties, see Note 8.

We establish provisions for losses on accounts receivable due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. The allowance for doubtful accounts as of December 31, 2013 and 2012 and the bad debt expense for the years ended December 31, 2013, 2012 and 2011 were not significant.

Inventories

Our inventories, which consist of materials and supplies, are valued at the lower of cost or market value with cost determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the amount of natural gas delivered from or received by a pipeline system differs from the scheduled amount of gas delivered or received. We value these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in cash or made up in-kind, subject to the terms of the applicable FERC tariff. Imbalances due from others are reported in the Consolidated Balance Sheets as "Other current assets." Imbalances owed to others are reported in the Consolidated Balance Sheets as "Other current liabilities." We classify all imbalances as current as we expect them to be settled within a year.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. For constructed assets, we capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Our indirect construction costs primarily include an interest and equity return component (as more fully described below) and labor and related costs of departments associated with supporting construction activities. The indirect capitalized labor and related costs are based upon estimates of time spent supporting construction projects.

We use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The FERC-accepted depreciation rate is applied to the total cost of the group until the net book value equals the salvage value. For certain general plant, the asset is depreciated to zero. We re-evaluate depreciation rates each time we redevelop our transportation and storage rates to file with the FERC for an increase or decrease in rates. When property, plant and equipment is retired, accumulated depreciation and amortization is charged for the original cost of the assets in addition to the cost to remove, sell or dispose of the assets, less salvage value. We do not recognize gains or losses unless we sell or retire an entire operating unit, as determined by the FERC. We generally include gains or losses on dispositions of operating units in "Operations and maintenance" expense in our Consolidated Statements of Income. In those instances where we receive recovery in rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount. See Note 3 for information related to a regulatory asset we recorded associated with the sale of certain SNG assets.

Included in our property balances are base gas and working gas at our storage facilities. We periodically evaluate natural gas volumes at our storage facilities for gas losses. When events or circumstances indicate a loss has occurred, we recognize a loss in our income statement or defer the loss as a regulatory asset on our balance sheets if deemed probable of recovery through future rates charged to customers.

We capitalize a carrying cost (AFUDC) on debt and equity funds related to the construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on the average cost of debt. Interest costs capitalized are included as a reduction to "Interest expense, net" on our Consolidated Statements of Income. The equity portion is calculated based on the most recent FERC approved rate of return. Equity amounts capitalized are included in "Other, net" on our Consolidated Statements of Income.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We are required to operate and maintain our natural gas pipelines, storage systems and LNG facilities, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the asset retirement obligation for the substantial majority of our natural gas pipeline system assets and LNG facility assets because these assets have indeterminate lives.

We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record. Our asset retirement obligations were not significant as of December 31, 2013 and 2012.

Asset and Investment Divestitures/Impairments

We evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows.

We classify assets (or groups of assets) to be disposed of as held for sale when specific criteria have been met. The lower of the carrying value or the estimated fair value less the cost to sell those assets is considered to determine if recognition of an impairment is required. We cease depreciation and amortization of the assets in the period they are considered held for sale.

Equity Method of Accounting

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

Revenue Recognition

Our revenues are primarily generated from natural gas transportation, storage and processing services as well as from LNG storage services and terminal operations and include estimates of amounts earned but unbilled. We estimate these unbilled revenues based on contract data, regulatory information, and preliminary throughput and allocation measurements, among other items. Revenues for all services are based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. For contracts with step-up or step-down rate provisions that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. Gas not used in operations is based on the volumes we are allowed to retain relative to the amounts of gas we use for operating purposes.

We recognize revenue from gas not used in operations from our shippers when the FERC allows us to retain the volumes at the market prices required under our tariffs. We are subject to FERC regulations and, as a result, revenues we collect may be subject to refund in a rate proceeding. We had no reserves for potential refunds as of December 31, 2013 and 2012.

Environmental Matters

We expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable. For more information on our environmental disclosures, see Note 9.

Legal

We are subject to litigation and regulatory proceedings as the result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such litigation based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on our legal disclosures, see Note 9.

Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue an undiscounted liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

Postretirement Benefits

CIG and SNG, our consolidated subsidiaries, maintain a postretirement benefit plan covering certain of their former employees. The plan requires them to make contributions to fund the benefits to be paid out under the plan. These contributions are invested until the benefits are paid out to plan participants. The net benefit cost of the plan is recorded in our Consolidated Statements of Income and is a function of many factors including benefits earned during the year by plan participants (which is a function of factors such as the level of benefits provided under the plan, actuarial assumptions and the passage of time), expected returns on plan assets and amortization of certain deferred gains and losses. For a further discussion of our policies with respect to CIG's and SNG's postretirement benefit plan, see Note 6.

In accounting for CIG's and SNG's postretirement benefit plan, we record an asset or liability based on the difference between the fair value of the plan's assets and the plan's benefit obligation. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either a regulatory asset or liability or recorded as "Other comprehensive income" until those gains or losses are recognized on our Consolidated Statements of Income.

Noncontrolling Interests

Noncontrolling interests represent the outstanding ownership interests in our consolidated operating limited partnerships that are not owned by us. In our accompanying Consolidated Statements of Income, the noncontrolling interests in our net income are shown as an allocation of our consolidated net income and are presented separately as “Net income attributable to noncontrolling interests.” In our accompanying Consolidated Balance Sheets, noncontrolling interests represent the ownership interests in our net assets held by parties other than us and are presented separately as “Noncontrolling interests.” For the year ended December 31, 2013, we had no non-wholly owned consolidated subsidiaries.

Limited Partners' Net Income per Unit

We compute “Limited partners' net income per unit” by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period.

Partners' Capital

We allocate our net income to the capital accounts of our general partner and limited partner unitholders based on the terms of the partnership agreement. The agreement requires these allocations to be made based on the relative percentage of their ownership interests, adjusted for any replenishment of previously allocated aggregate net losses and/or special allocations, each as defined in our partnership agreement. As a result of the retrospective consolidation of CIG, SNG and CPG, earnings prior to the acquisitions of the incremental interests in these subsidiaries (pre-acquisition earnings) have been allocated solely to our general partner. See Note 3 for additional information related to the retrospective consolidation of subsidiaries to reflect the reorganization of entities under common control and the change in reporting entity.

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities on the terms and conditions determined by our general partner without the approval of our unitholders. Accordingly, all of our issued units are authorized and outstanding, and there are an unlimited number of units that are authorized beyond those currently issued.

Regulated Operations

Our interstate natural gas pipelines, storage operations and LNG receiving terminal are subject to the jurisdiction of the FERC and follow the FASB's accounting standards for regulated operations. Under these standards, we record regulatory assets and liabilities that would not be recorded for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges or credits that are expected to be recovered from or refunded to customers through the rate making process. Items to which we apply regulatory accounting requirements include certain postretirement benefit plan costs, losses on reacquired debt, losses on the sale of certain long lived assets, taxes related to an equity return component on regulated capital projects in periods prior to our subsidiaries' change in legal structure to non-taxable entities, certain cost differences between gas retained and gas consumed in operations and other costs included in, or expected to be included in, future rates. See Note 11 for further discussion regarding our regulated operations.

3. Acquisitions and Divestitures

2011 Acquisitions

In March 2011, we acquired an additional 25% interest in SNG from El Paso for $667 million in cash. We financed the acquisition through (i) net proceeds of $467 million from our March 2011 public offering of common units and related issuance of general partner units to El Paso and (ii) $200 million borrowings under our revolving credit agreement. This transaction was for the acquisition of an additional interest in an already consolidated entity, thus was accounted for on a prospective basis.

In June 2011, we acquired the remaining 15% interest in SNG and an additional 28% interest in CIG from El Paso for $745 million in cash. We financed the acquisition through (i) net proceeds of $501 million from our May 2011 public offering of common units and related issuance of general partner units to El Paso, including the underwriters’ June 2011 exercise of the overallotment option and (ii) $244 million borrowings under our revolving credit agreement. This transaction was for the acquisition of additional interests in already consolidated entities, thus was accounted for on a prospective basis.

We have decreased our historical noncontrolling interests in SNG and CIG for both the March and June 2011 acquisitions by $896 million and reflected that amount as an increase to "General Partner’s Capital." We reflected El Paso’s interest in SNG and CIG as noncontrolling interest in our financial statements. El Paso’s interest in SNG was 40% from January 1, 2011 to March 13, 2011 and 15% until the June 29, 2011 acquisition of the remaining interest. Subsequent to the June 2011 acquisition, SNG became a wholly owned subsidiary of EPB. We reflected El Paso’s 42% interest in CIG as noncontrolling interest in our financial statements for the period from January 1, 2011 to June 29, 2011 and 14% until the May 24, 2012 acquisition of the remaining interest.

2012 Acquisitions

In May 2012, we acquired the remaining 14% interest in CIG and a 100% interest in CPG from El Paso for $635 million. The consideration paid to El Paso consisted of $571 million in cash and the issuance of common units. We financed the cash payment through (i) $570 million in borrowings under our credit agreement and (ii) $1 million from the issuance of general partner units. We recorded our interest in CPG at its historical cost of $ 185 million and the excess cash paid over contributed book value of $180 million as a decrease to general partner's capital. Also decreasing general partner's capital was $206 million of cash paid to acquire the remaining interest in CIG. Subsequent to the acquisition, we had the ability to control CPG's operating and financial decisions and policies and have consolidated CPG in our financial statements. We have retrospectively adjusted our historical financial statements in all periods presented to reflect the reorganization of entities under common control and the change in reporting entity. As a result of the retrospective consolidation, the pre-acquisition earnings of CPG have been allocated solely to our general partner. The retrospective consolidation of CPG increased net income attributable to El Paso Pipeline Partners, L.P. by $22 million and $40 million and for 2012 and 2011, respectively. The acquisition of the remaining interest in CIG was for an additional interest in an already consolidated entity; therefore, it was accounted for prospectively. We have decreased the remaining noncontrolling interest in CIG for the May 2012 acquisition by $115 million and reflected that amount as an increase to "General Partner's Capital" and "Accumulated other comprehensive income (loss)."

For additional information related to the funding of our acquisitions with debt and equity issuances, see Notes 5 and 7, respectively.

Divestitures

SNG Assets

In September 2011, SNG entered into an agreement to sell certain offshore and onshore assets (including pipeline, platforms and other related assets located in the Gulf of Mexico and Louisiana) for approximately $50 million. SNG deferred the estimated loss as a regulatory asset. On June 21, 2012, the FERC issued an order approving the sale, which occurred on November 1, 2012. The regulatory asset balance as of December 31, 2012 of $36 million represented the difference between the net book value and the $50 million sales price amortized by a fixed monthly rate pursuant to the settlement of SNG's rate case. As of December 31, 2013, the regulatory asset balance was $23 million. In accordance with the settlement of SNG's rate case, which was approved by the FERC on July 12, 2013, the recovery of the total regulatory asset will occur over a three-year period ending October 31, 2015.

4. Property, Plant and Equipment

Classes of Assets and Depreciation Rates

As of December 31, 2013 and 2012, our property plant and equipment consisted of the following (in millions, except for %):

	Annual Depreciation Rates	December 31,	
	(%)	2013	2012
Transmission and storage facilities	0.9-10.0	$ 7,886	$ 7,779
General plant	1.76-25.0	66	67
Intangible plant	1.76-23.0	126	128
Other		196	202
Accumulated depreciation and amortization (a)		(2,472)	(2,321)
		5,802	5,855
Land		24	24
Construction work in progress		53	52
Property, plant and equipment, net		$ 5,879	$ 5,931

(a) The composite weighted average depreciation rates for the years ended December 31, 2013, 2012 and 2011 were 2.29%, 2.18% and 2.19%, respectively.

Capitalized Costs During Construction

The allowance for debt interest amounts capitalized during the years ended December 31, 2013, 2012 and 2011 was $1 million, $1 million and $2 million, respectively. The allowance for equity amounts capitalized during each of the years ended December 31, 2013, 2012 and 2011 was $2 million, $3 million and $7 million, respectively.

5. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our Consolidated Statements of Income. The following table summarizes the net carrying value of our outstanding debt (in millions):

	As of December 31,	
	2013	2012
EPPOC		
Senior Notes, 8.00%, due 2013	$ —	$ 88
Senior Notes, 4.10%, due 2015	375	375
Senior Notes, 6.50%, due 2020	535	535
Senior Notes, 5.00%, due 2021	500	500
Senior Notes, 7.50%, due 2040	375	375
Senior Notes, 4.70%, due 2042	475	475
Revolving credit agreement, variable, due 2016 (a)	—	—
CIG		
Senior Notes, 5.95%, due 2015	35	35
Senior Notes, 6.80%, due 2015	340	340
Senior Debentures, 6.85%, due 2037	100	100
SLNG		
Senior Notes, 9.50%, due 2014	71	71
Senior Notes, 9.75%, due 2016	64	64
SNG		
Notes, 5.90%, due 2017	500	500
Notes, 4.40%, due 2021	300	300
Notes, 7.35%, due 2031	153	153
Notes, 8.00%, due 2032	258	258
Total long-term debt	4,081	4,169
Other financing obligations	175	178
Total long-term debt and other financing obligations	4,256	4,347
Less: Unamortized discount	8	8
Current maturities	77	93
Total long-term debt and other financing obligations, less current maturities	$ 4,171	$ 4,246

(a) LIBOR plus 1.75%.

Credit Agreement

In May 2011, EPPOC and WIC entered into an unsecured 5-year credit agreement with an initial aggregate borrowing capacity of $1.0 billion, expandable to $1.5 billion for certain expansion projects and acquisitions. EPPOC is a wholly owned subsidiary of EPB. In May 2012, we borrowed from our revolving credit agreement to fund the acquisition of CPG and the remaining interest in CIG (see Note 3). On May 24, 2012, Standard & Poor's raised our credit rating, triggering a pricing level change. Our interest rate for borrowings under our credit agreement has decreased from the LIBOR plus 2% to LIBOR plus 1.75% and the commitment fee paid for unutilized commitments decreased from 0.4% to 0.3% and these rates remained effective at December 31, 2013. At December 31, 2013, EPPOC's senior debt was rated investment grade by Fitch Ratings (BBB-) and Standard & Poor's (BBB-) and below investment grade by Moody's Investor Services (Ba1). During 2013, we drew and repaid $87 million from our revolving credit agreement and as of December 31, 2013, we had no outstanding balance. Our remaining availability under this facility was $ 1.0 billion. Borrowings under the credit agreement are guaranteed by EPB.

The credit agreement contains covenants and provisions that affect us, the borrowers and our other restricted subsidiaries, including, without limitation, customary covenants and provisions:

- prohibiting the borrowers from creating or incurring indebtedness (except for certain specified permitted indebtedness) if such incurrence would cause a breach of the leverage ratio described below;
- limiting our ability and that of the borrowers and our other restricted subsidiaries from creating or incurring certain liens on our respective properties (subject to enumerated exceptions);
- limiting our ability to make distributions and equity repurchases (which shall be permitted if no insolvency default or event of default exists); and
- prohibiting consolidations, mergers and asset transfers by us, the borrowers and our other restricted subsidiaries (subject to enumerated exceptions).

The credit agreement requires that EPB and WIC maintain a consolidated leverage ratio (consolidated indebtedness to consolidated EBITDA) as defined in the credit agreement as of the end of each quarter of less than 5.0 to 1.0 for any trailing four consecutive quarter period; and 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified permitted acquisitions having a value greater than $25 million. We also have additional flexibility to our covenants for growth projects. In case of a capital construction or expansion project in excess of $20 million, pro forma adjustments to consolidated EBITDA, approved by the lenders, may be made based on the percentage of capital costs expended and projected cash flows for the project. Such adjustments shall be limited to 25% of actual consolidated EBITDA.

The credit agreement contains certain customary events of default that affect us, the borrowers and our other restricted subsidiaries, including, without limitation, (i) nonpayment of principal when due or nonpayment of interest or other amounts within 5 business days of when due; (ii) bankruptcy or insolvency with respect to us, our general partner, the borrowers or any of our other restricted subsidiaries; (iii) judgment defaults against us, our general partner, the borrowers or any of our other restricted subsidiaries in excess of $50 million; or (iv) the failure of El Paso to directly or indirectly own a majority of the voting equity of our general partner and a failure by us to directly or indirectly own 100% of the equity of EPPOC. As of December 31, 2013 and 2012, we were in compliance with the credit agreement covenants.

EPPOC Senior Notes

EPPOC's senior notes are guaranteed fully and unconditionally by its parent, EPB. EPPOC is a wholly owned subsidiary of EPB. EPB's only operating asset is its investment in EPPOC, and EPPOC's only operating assets are its investments in WIC, CIG, SLNG, Elba Express, SNG, ELC and CPG (collectively, the non-guarantor operating companies). EPB's and EPPOC's independent assets and operations, other than those related to these investments and EPPOC's debt are less than 3% of the total assets and operations of EPB, and thus substantially all of the operations and assets exist within these non-guarantor operating companies. Furthermore, there are no significant restrictions on EPPOC's or EPB's ability to access the net assets or cash flows related to their controlling interests in the operating companies either through dividend or loan. The restrictive covenants under these debt obligations are no more restrictive than the restrictive covenants under our credit agreement. As of December 31, 2013 and 2012, EPPOC was in compliance with all of its debt related covenants.

In November 2012, EPPOC issued $475 million of 4.7% senior notes due in 2042. The net proceeds of $469 million were used to reduce outstanding indebtedness under EPB's revolving credit agreement and for general partnership purposes.

In September 2013, EPPOC repaid $88 million of 8.00% senior notes.

CIG Debt

CIG is subject to a number of restrictions and covenants under its debt obligation. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions. For the year ended December 31, 2013 and 2012, CIG was in compliance with its debt-related covenants.

SLNG Debt

The SLNG senior notes impose certain limitations on the ability of SLNG to, among other things, incur additional indebtedness, make certain restricted payments, enter into transactions with affiliates, and merge or consolidate with any other person, sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its assets. SLNG is required to comply with certain financial covenants, including a leverage ratio of no more than 5.0 to 1.0 and an interest coverage ratio of no less than 2.0 to 1.0.

The SLNG senior notes are unsecured and are redeemable at SLNG's option at 100% of the principal amount plus a specified make-whole premium. The SLNG notes are also subject to a change of control prepayment offer in the event of a ratings downgrade within a 120-day period from and including the date on which a change of control with respect to SLNG occurs (as defined in the note purchase agreement). If a sufficient number of the rating agencies downgrade the ratings of the SLNG notes below investment grade within the 120-day period from and including the date of any such change of control, then SLNG is required to offer to prepay the entire unpaid principal amount of the notes held by each holder at 101% of the principal amount of such SLNG notes (without any make-whole amount or other penalty), together with interest accrued thereon to the date for such prepayment. As of December 31, 2013 and 2012, SLNG was in compliance with its debt related covenants.

SNG Debt

Under its indentures, SNG is subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens. As of December 31, 2013 and 2012, SNG was in compliance with debt-related covenants.

Southern Natural Issuing Corporation (SNIC) is a wholly owned finance subsidiary of SNG and is the co-issuer of certain of SNG's outstanding debt securities. SNIC has no material assets, operations, revenues or cash flows other than those related to its service as a co-issuer of the debt securities. Accordingly, it has no ability to service obligations on the debt securities.

CPG Debt

In May 2005, CPG entered into a $266 million nonrecourse project financing agreement with a maturity date of March 31, 2015. During 2012, we made principal and interests payments of $8 million. Additionally, in September 2012, we repaid the remaining borrowings of $ 172 million under the term loan and canceled a related $12 million letter of credit. See Note 10 for information related to the settlement of the interest rate swaps associated with this loan agreement.

Other Financing Obligations

In conjunction with the construction of Totem and High Plains, CIG's joint venture partner in WYCO funded 50% of the construction costs. We reflected the payments made by their joint venture partner as other long-term liabilities on the balance sheet during construction and, upon project completion, the advances were converted into a financing obligation to WYCO. Upon placing these projects in service, we transferred our title in the projects to WYCO and leased the assets back. Although we transferred the title in these projects to WYCO, the transfer did not qualify for sale leaseback accounting because of our continuing involvement through our equity investment in WYCO. As such, the costs of the facilities remain on our balance sheets and the advanced payments received from our 50% joint venture partner were converted into a financing obligation due to WYCO.

As of December 31, 2013, the principal amounts of the Totem and High Plains financing obligations were $75 million and $94 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. The effective interest rate on these obligations is 15.5%, payable on a monthly basis.

Maturities of Debt

The scheduled maturities of our outstanding debt as of December 31, 2013 are summarized as follows (in millions):

Year	Commitment
2014	$ 77
2015	756
2016	69
2017	505
2018	5
Thereafter	2,844
Total long-term debt and other financing obligations	$ 4,256

6. Retirement Benefits

Pension and Retirement Savings Plans

KMI maintains a pension plan and a retirement savings plan covering substantially all of its U.S. employees, including CIG's and SNG's former employees. The benefits under the pension plan are determined under a cash balance formula. Under its retirement savings plan, KMI contributes an amount equal to 5% of participants' eligible compensation per year. KMI is responsible for benefits accrued under its plans and allocates the related costs based on a benefit allocation rate applied on payroll charged to its affiliates.

Postretirement Benefit Plans

CIG and SNG provide postretirement medical benefits for a closed group of retirees. These benefits may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs and are subject to further benefit changes by KMI, the plan sponsor. In addition, certain former employees continue to receive limited postretirement life insurance benefits. Postretirement benefit plan costs are prefunded to the extent these costs are recoverable through rates. To the extent actual costs differ from the amounts recovered in rates, either "Accumulated other comprehensive income" or a regulatory asset or liability is recorded. We expect to make no contributions to our postretirement benefit plan in 2014. Contributions of approximately $1 million were made to the postretirement benefit plan for the years ended December 31, 2013, 2012 and 2011.

Accumulated Postretirement Benefit Obligation, Plan Assets and Funded Status

In accounting for the postretirement benefit plan, we record an asset or liability based on the overfunded or underfunded status. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either "Accumulated other comprehensive income" or a regulatory asset or liability. As part of the rate case settlement as discussed in Note 11, CIG will no longer include these costs in their rates.

The table below provides information about the postretirement benefit plan (in millions):

	December 31,	
	2013	2012
Change in accumulated postretirement benefit obligation:		
Accumulated postretirement benefit obligation — beginning of period	$ 63	$ 55
Interest cost	2	2
Participant contributions	1	1
Plan amendments	(19)	—
Actuarial (gain) loss	(4)	10
Benefits paid(a)	(4)	(5)
Accumulated postretirement benefit obligation — end of period	$ 39	$ 63
Change in plan assets:		
Fair value of plan assets — beginning of period	$ 78	$ 72
Actual return on plan assets	9	9
Employer contributions	1	1
Participant contributions	1	1
Benefits paid	(5)	(5)
Fair value of plan assets — end of period	$ 84	$ 78
Reconciliation of funded status:		
Fair value of plan assets	$ 84	$ 78
Less: accumulated postretirement benefit obligation	39	63
Net asset at December 31(b)	$ 45	$ 15

(a) Amount shown net of a subsidy of $1 million for the year ended December 31, 2013 and less than $1 million for the year ended December 31, 2012 related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

(b) Net asset amounts are included in "Deferred charges and other assets" in our Consolidated Balance Sheets.

Components of Accumulated Other Comprehensive Income

The amount recognized in "Accumulated other comprehensive income" for CIG as of December 31, 2013 and 2012 of $10 million for each period is primarily related to unrecognized gains. We anticipate that approximately $1 million of "Accumulated other comprehensive income" will be recognized as part of net periodic benefit income in 2014.

Plan Assets

The primary investment objective of the plan is to ensure that, over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to meet the benefit obligations to retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is generally the result of economic and capital market conditions. Although actual allocations vary from time to time from the targeted allocations, the target allocations of the plan's assets are 70% equity and 30% fixed income securities.

We use various methods to determine the fair values of the assets in the postretirement benefit plan, which are impacted by a number of factors, including the availability of observable market data over the contractual term of the underlying assets. We separate the plan's assets into three levels (Level 1, 2 and 3) based on our assessment of the availability of market data and the significance of non-observable data used to determine the fair value of these assets. As of December 31, 2013, assets were comprised of domestic equity securities with a fair value of $3 million, a fixed income mutual fund with a fair value of $25 million and limited partnership funds with equity strategies with a fair value of $56 million. For the domestic equity securities, mutual fund and $29 million of the limited partnership funds, the fair value (which is considered a Level 1 measurement) is determined based on the price quoted for the investment in actively traded markets. Approximately $27 million of the limited partnership balance is comprised of a limited partnership fund, for which the fair value (which is considered a Level 2 measurement) is determined primarily based on the net asset value reported by the issuer, which is based on similar assets in active markets. As of December 31, 2012, assets were comprised of a mutual fund with a fair value of $4 million and common/collective trust funds with a fair value of $74 million. The mutual fund invests primarily in dollar-denominated securities, and its fair value (which is considered a Level 1 measurement) is determined based on the price quoted for the fund in actively traded markets. The common/collective trust funds are invested in approximately 65% equity and 35% fixed income securities, and their fair values (which are considered Level 2 measurements) are determined primarily based on the net asset value reported by the issuer, which is based on similar assets in active markets. Certain restrictions on withdrawals exist for the limited partnerships and common/collective trust funds where the issuer reserves the right to temporarily delay withdrawals in certain situations such as market conditions or at the issuer's discretion. The plan does not have any assets that are considered Level 3 measurements. The methods described above may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. There have been no changes in the methodologies used at December 31, 2013 and 2012.

Expected Payment of Future Benefits

As of December 31, 2013, we expect the following benefit payments under the plan (in millions):

Year Ending December 31,	Expected Payments
2014	$ 4
2015	4
2016	4
2017	3
2018	3
2019 - 2023	14

Actuarial Assumptions and Sensitivity Analysis

Accumulated postretirement benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used in determining the postretirement plan's obligations and net benefit costs.

	2013	2012	2011
		(%)	
Assumptions related to benefit obligations at December 31:			
Discount rate	4.17	3.45	4.43
Assumptions related to benefit costs for the year ended December 31:			
Discount rate(a)	3.62	4.25	4.90
Expected return on plan assets(b)	7.50	7.50	7.75

(a) The discount rates related to benefit costs were 4.42% for the period from January 1, 2012 to May 24, 2012, and 4.12% for the period from May 25, 2012 to December 31, 2012.

(b) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. We utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes with a weighted average rate of 24% for 2013, 22% for 2012 and 35% for 2011.

Actuarial estimates for the plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 7%, gradually decreasing to 5% by the year 2019. A one-percentage point change would not have a significant effect on interest costs in 2013 and 2012. A one-percentage point change in assumed health care trends would not have a significant effect on the accumulated postretirement benefit obligation as of December 31, 2013 and would have the following effect as of December 31, 2012 (in millions):

	2012
One percentage point increase:	
Accumulated postretirement benefit obligation	$ 6
One percentage point decrease:	
Accumulated postretirement benefit obligation	(5)

Components of Net Benefit Income

For each of the years ended December 31, the components of net benefit income are as follows (in millions):

	2013	2012	2011
Interest cost	$ 2	$ 2	$ 3
Expected return on plan assets	(7)	(5)	(4)
Net benefit income	$ (5)	$ (3)	$ (1)

7. Partners' Capital

As of December 31, 2013, 2012 and 2011, our partners' capital included the following limited partner and general partner units:

	December 31,		
	2013	2012	2011
Common units:			
Held by third parties	127,510,832	125,468,515	117,298,691
Held by KMI and affiliates	90,320,810	90,320,810	88,400,059
Total limited partner units	217,831,642	215,789,325	205,698,750
General partner units	4,445,455	4,403,765	4,197,822
Total outstanding units	222,277,097	220,193,090	209,896,572

As of December 31, 2013, KMI owns a 41% limited partner interest in us and retains its 2% general partner interest in us and all of our IDRs.

The table below provides a reconciliation of our limited and general partner units.

	Unit Reconciliation			
	Limited Partner Units			
	Common	Subordinated	General Partner	Total Partners' Capital
Balance at December 31, 2010	149,440,452	27,727,411	3,615,578	180,783,441
Unit-based compensation to non-employee directors	5,481	—	—	5,481
Conversion of subordinated units to common units (a)	27,727,411	(27,727,411)	—	—
Issuance of units	28,525,406	—	582,244	29,107,650
Balance at December 31, 2011	205,698,750	—	4,197,822	209,896,572
Unit-based compensation to non-employee directors	4,824	—	—	4,824
Issuance of units	8,165,000	—	166,744	8,331,744
Acquisition of interest in CPG and CIG	1,920,751	—	39,199	1,959,950
Balance at December 31, 2012	215,789,325	—	4,403,765	220,193,090
Unit-based compensation to non-employee directors	4,359	—	—	4,359
Issuance of units	2,037,958	—	41,690	2,079,648
Balance at December 31, 2013	217,831,642	—	4,445,455	222,277,097

(a) All subordinated units were converted to common units on a one-for-one basis effective January 3, 2011. See additional discussion below regarding subordinated units.

Equity Issuances

On March 7, 2013, we entered into an equity distribution agreement with Citigroup Global Markets, Inc. (Citigroup). Pursuant to the provisions of the equity distribution agreement, we may sell from time to time through Citigroup, as our sales agent, common units representing limited partner interests having an aggregate offering price of up to $500 million. Sales of the common units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and Citigroup. Under the terms of the equity distribution agreement, we may also sell common units to Citigroup as principal for its own account at a price agreed upon at the time of the sale. Any sale of the common units to Citigroup as principal would be pursuant to the terms of a separate agreement between us and Citigroup. The equity distribution agreement provides us with the right, but not the obligation, to offer and sell common units, at prices to be determined by market conditions. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through Citigroup, on a daily basis or otherwise as we and Citigroup agree.

We issued common units to the public and issued general partner units to KMI and affiliates. The net proceeds from the offerings were used as partial consideration to fund acquisitions from KMI and affiliates and general partnership purposes. The table below shows the units issued, the net proceeds for the issuances (in millions) and the ultimate use of the proceeds:

Issuance Date	Common Units(b)	General Partner Units(c)	Net Proceeds(d)	Use of Proceeds
First Quarter 2011	13,800,000	281,725	$ 467	Additional 25% interest in SNG
Second Quarter 2011(a)	14,725,406	300,519	501	Additional 28% interest in CIG and remaining 15% interest in SNG
Third Quarter 2012(a)	8,165,000	166,744	278	Repayment of CPG debt, certain short-term debt and general partnership purposes
First Quarter 2013	525,900	10,831	22	General Partnership purposes
Second Quarter 2013	1,512,058	30,859	65	General Partnership purposes

(a) Includes the underwriters' exercise of the overallotment option.
(b) The 2013 issuances are pursuant to our equity distribution agreement.
(c) Units issued to the general partner to maintain its 2% ownership interest in us.
(d) Net proceeds include proceeds from issuances to our general partner.

In addition, in May 2012, we issued 1,920,751 common units and 39,199 general partner units to El Paso in conjunction with our acquisition of CPG and the remainder of CIG. See Note 3 for further discussion.

Earnings per Unit

Earnings per unit is calculated based on distributions declared to our unitholders, including distributions related to the IDRs for the related reporting period. To the extent net income attributable to EPB exceeds cash distributions, the excess is allocated to unitholders and the holder of IDRs based on their contractual participation rights to share in those earnings. If cash distributions exceed net income attributable to EPB, the excess distributions are allocated proportionately to all participating units outstanding based on their respective ownership percentages. Additionally, the calculation of earnings per unit does not reflect an allocation of undistributed earnings to the IDR holders beyond amounts distributable under the terms of the partnership agreement. Payments made to our unitholders are determined in relation to actual declared distributions and are not based on the net income allocations used in the calculation of earnings per unit.

As discussed in Note 3, we have retrospectively adjusted our historical financial statements for the consolidations of CPG following the acquisitions of its controlling interest. As a result of the retrospective consolidation, earnings prior to the acquisition of the incremental interest (pre-acquisition earnings) in CPG has been allocated solely to our general partner in all periods presented.

Net income attributable to EPB per limited partner unit is computed by dividing the limited partners' interest in net income attributable to EPB by the weighted average number of limited partner units outstanding. Diluted earnings per limited partner unit reflects the potential dilution that could occur if securities or other agreements to issue common units were exercised, settled or converted into common units. As of December 31, 2013 and 2012, the dilutive, restricted units outstanding were immaterial.

Subordinated units

All of the subordinated units were held by a wholly owned subsidiary of El Paso. Our partnership agreement provided that, during the subordination period, the common units would have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.2875 per common unit, which is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus were made on the subordinated units. Furthermore, no arrearages would be paid on the subordinated units. The practical effect of the subordinated units was to increase the likelihood that during the subordination period there would be available cash to be distributed on the common units.

Upon payment of the quarterly cash distribution payment for the fourth quarter of 2010, the financial tests required for the conversion of all subordinated units into common units were satisfied. As a result, all of the subordinated units held by affiliates of El Paso were converted on February 15, 2011 on a one-for-one basis into common units effective January 3, 2011. The conversion did not impact the amount of cash distribution paid or the total number of the Partnership's outstanding units.

Incentive Distribution Rights

Our general partner, as the holder of our IDRs, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and (upon satisfaction of certain conditions) to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. In connection with this election, our general partner would be entitled to receive a number of newly issued Class B common units and general partner units based on a predetermined formula. In April 2012, the conditions were met which entitled our general partner to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are set. As of December 31, 2013, our general partner has not elected to reset its minimum quarterly distribution amount and increase the cash target distribution levels upon which its IDR payments are made. Therefore, no Class B units have been issued as required by the general partner's reset election. Even if there has been no reset election, diluted earnings per unit may be affected if the impact of a potential reset is dilutive. Currently, diluted earnings per unit has not been impacted because the combined impact is antidilutive.

Our general partner currently holds all of our IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. The IDRs are considered a special non-voting limited partner interest under EPB's partnership agreement. For presentation purposes, we include income allocations and distributions related to the IDRs within general partner's capital because our general partner currently holds the IDRs. Based on the quarterly distribution per unit declared for the three months ended December 31, 2013, our general partner received an incentive distribution of $51 million on February 14, 2014 in accordance with the partnership agreement.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner, who currently owns our IDRs. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash distributions made to all partners.

Our partnership agreement requires that we distribute all of our available cash from operating surplus each quarter. We determine the allocation of incentive distributions to our general partner by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement summarized in the table below. The percentage interests set forth below for our general partner include its 2% general partner interest and assume our general partner has contributed any additional capital necessary to maintain its 2% general partner interest and has not transferred its IDRs.

	Total Quarterly Distribution per Unit Target Amount	Marginal Percentage Interest in Distribution	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.2875	98%	2%
First Target Distribution	above $0.2875 up to $0.33063	98%	2%
Second Target Distribution	above $0.33063 up to $0.35938	85%	15%
Third Target Distribution	above $0.35938 up to $0.43125	75%	25%
Thereafter	above $0.43125	50%	50%

The following table provides information about our distributions (in millions, except per unit distribution amounts):

	Year Ended December 31,		
	2013	2012	2011
Per unit cash distributions declared for the period	$ 2.55	$ 2.25	$ 1.93
Per unit cash distribution paid in the period (a)	2.51	2.14	1.87
Cash distributions paid in the period to all partners	746	564	422
General Partner's incentive distribution (b):			
Declared for the period	195	129	62
Paid in the period (a)	187	105	49

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

(b) The year-to-year increases in distributions paid reflect the increase in amounts distributed per unit as well as the issuance of additional units.

8. Related Party Transactions

Cash Distributions

CIG Cash Distributions to El Paso

CIG made quarterly distributions to its owners. We have reflected 42% of CIG's distributions paid to El Paso through June 2011 and 14% thereafter as distributions to its noncontrolling interest holder until CIG became a wholly owned subsidiary of EPB subsequent to the May 2012 acquisition (see Note 3).

SNG Cash Distributions to El Paso

SNG makes quarterly distributions to its owners. We have reflected 40% of SNG's distributions paid to El Paso through 2010 and 15% through the first quarter of 2011 as distributions to its noncontrolling interest holder. Subsequent to the June 2011 acquisition as described in Note 3, SNG became a wholly owned subsidiary of EPB.

CPG Cash Distributions to El Paso

Due to the retrospective consolidation of CPG, as discussed in Note 3, we have reflected CPG's historical distributions paid to El Paso prior to our consolidation in May 2012 as distributions of pre-acquisition earnings which are allocated solely to our general partner.

The following table summarizes our cash distributions paid to El Paso prior to KMI's acquisition of El Paso (in millions):

	Year Ended December 31,	
	2012	2011
CIG distributions to noncontrolling interest holder	$ 13	$ 48
SNG distributions to noncontrolling interest holder	—	31
CPG distributions of pre-acquisition earnings	15	37
Total Cash Distributions to El Paso	$ 28	$ 116

Contributions to Subsidiaries

During 2011, El Paso made capital contributions of $15 million to each of CIG and SNG, respectively, to fund their share of expansion project expenditures. In addition, prior to our acquisition of CPG, El Paso made a cash contribution to CPG in 2011 of $4 million. During 2012, El Paso made a capital contribution of $2 million to CIG to fund its share of expansion project expenditures.

Contributions to Equity Method Investment

During 2013, we made capital contributions of $13 million to ELC, our equity method investment, to fund its share of expansion project expenditures.

Affiliate Balances

We enter into transactions with our affiliates within the ordinary course of business and the services are based on the same terms as non-affiliates, including natural gas transportation services to and from affiliates under long-term contracts and various operating agreements.

We do not have employees. Employees of KMI and its affiliates provide services to our general partner, us and our subsidiaries. We are managed and operated by the directors and officers of our general partner, El Paso Pipeline GP Company, L.L.C., a subsidiary of KMI. Under an omnibus agreement with El Paso and other policies with KMI and its affiliates, we reimburse KMI and its affiliates without a profit component for the provision of various general and administrative services for our benefit and for direct expenses incurred by KMI or its affiliates on our behalf. KMI bills us directly for certain general and administrative costs and allocates a portion of its general and administrative costs without a profit component to us. Prior to KMI's acquisition of El Paso, we were allocated costs from EPNG and TGP, our affiliates, associated with our pipeline services. The allocations from TGP, EPNG and El Paso were based on the estimated level of effort devoted to our operations and the relative size of our earnings before interest expense and income taxes, gross property and payroll.

The following table summarizes our balance sheet affiliate balances (in millions):

	December 31,	
	2013	2012
Accounts receivable, net	$ 3	$ 7
Natural gas imbalance receivable (a)	2	2
Accounts payable	9	13
Financing obligations(b)	175	178

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(a) Included in "Other current assets" on our Consolidated Balance Sheets.

(b) Represents financing obligations payable to WYCO related to Totem and High Plains, of which $6 million and $5 million is included in "Current portion of debt" on our Consolidated Balance Sheets as of December 31, 2013 and 2012, respectively. See Note 5 for a further discussion of these obligations.

The table below shows overall revenues, expenses and reimbursements from our affiliates for the years ended December 31, 2013, 2012 and 2011 (in millions):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 8	$ 13	$ 19
Operating expenses(a)	156	224	242
Reimbursement of operating expenses	—	3	4

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(a) Includes non-cash severance costs of $1 million and $34 million for the years ended December 31, 2013 and 2012, respectively, allocated to us from our general partner as a result of KMI's acquisition of El Paso; however, we do not have any obligation nor did we pay any amounts related to this expense.

9. Litigation, Environmental and Other Contingencies

We are party to various legal, regulatory and other matters arising from the day-to-day operations of our businesses that may result in claims against us. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend these matters. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

Legal Proceedings

Brinckerhoff v. El Paso Pipeline GP Company, LLC., et al.

In December 2011 (“*Brinckerhoff I*”), March 2012, (“*Brinckerhoff II*”) and May 2013 (*"Brinckerhoff III"*), derivative lawsuits were filed in Delaware Chancery Court against El Paso, El Paso Pipeline GP Company, L.L.C., our general partner and the directors of our general partner. We were named in these lawsuits as a “Nominal Defendant.” The lawsuits arise from the March 2010, November 2010 and May 2012 drop down transactions involving our purchase of SLNG, Elba Express, CPG and interests in SNG and CIG. The lawsuits allege various conflicts of interest and that the consideration we paid was excessive. Defendants' motion to dismiss in Brinckerhoff I was denied in part. Brinckerhoff I and II have been consolidated into one proceeding. The parties' motions for summary judgment are pending. A motion to dismiss has been filed in Brinckerhoff III. Defendants continue to believe that these actions are without merit and intend to defend against them vigorously.

Allen v. El Paso Pipeline GP Company, L.L.C., et al.

In May 2012, a unitholder of EPB filed a purported class action in Delaware Chancery Court, alleging both derivative and non-derivative claims, against us, and our general partner and its board. We were named in the lawsuit as both a “Class Defendant” and a “Derivative Nominal Defendant.” The complaint alleges a breach of the duty of good faith and fair dealing in connection with the March 2011 sale to us of a 25% ownership interest in SNG. Defendants' motion to dismiss was denied. Defendants' motion for summary judgment is pending. Defendants continue to believe this action is without merit and intend to defend against it vigorously.

General

As of December 31, 2013 and 2012, our total reserve for legal proceedings amounted to $2 million.

Environmental Matters

We are subject to environmental cleanup and enforcement actions from time to time. Our operations are subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in our operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

Southeast Louisiana Flood Protection Litigation

On July 24, 2013, the Board of Commissioners of the Southeast Louisiana Flood Protection Authority- East filed a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana (Case No. 13-6911) against SNG, and approximately one hundred other energy companies, alleging that defendants' drilling, dredging, pipeline and industrial operations since the 1930's have caused direct land loss and increased erosion and submergence resulting in alleged increased storm surge risk, increased flood protection costs and unspecified damages to the plaintiff. The Flood Protection Authority asserts claims for negligence, strict liability, public nuisance, private nuisance, and breach of contract. Among other relief, the petition seeks unspecified monetary damages, attorney fees, interest, and injunctive relief in the form of abatement and restoration of the alleged coastal land loss including but not limited to backfilling and re-vegetation of canals, wetlands and reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, and bank stabilization. On August 13, 2013, the suit was removed to the U.S. District Court for the Eastern District of Louisiana. On September 10, 2013, the Flood Protection Authority filed a motion to remand the case to the state district court for Orleans Parish. On December 18, 2013, a hearing was conducted on the remand motion and it remains under consideration by the court.

Superfund Matters

Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a PRP under the CERCLA, commonly known as Superfund, or state equivalents for one active site. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we are a party, will not have a material adverse effect on our business, financial position, results of operations or cash distributions. As of December 31, 2013 and 2012, we had approximately $2 million and $3 million accrued for our environmental matters.

Other Commitments

Capital Contributions for Elba Island Liquefaction Project

In January 2013, SLC, a subsidiary of EPB and Shell G&P, a subsidiary of Royal Dutch Shell plc (Shell), formed ELC, our equity method investment, to develop and own a natural gas liquefaction plant at SLNG's existing Elba Island LNG terminal. In connection with the formation of ELC, SLC and Shell G&P entered into a LLC agreement in which SLC owns 51% of ELC and Shell G&P owns the remaining membership interest. Under the terms of the LLC agreement, SLC and Shell G&P are both obligated to make certain capital contributions in proportion to their membership interests in ELC to fund the construction of the liquefaction facilities. EPB's investment at the terminal in Phase I, including both the liquefaction facilities and SLNG ancillary facilities, is estimated to be approximately $800 million. Phase I of the project requires no additional DOE approval.

Other Capital Commitments

At December 31, 2013, we have capital commitments of approximately $5 million related to Southeast Supply Header, all of which will be spent in 2014. We also have commitments for the purchase of plant, property and equipment of $12 million, which we expect to spend during 2014. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

Other Commercial Commitments

We hold cancelable easement or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems. Currently, our obligations under these easements are not material to the results of our operations.

Transportation and Storage Commitments

We have entered into transportation commitments and storage capacity contracts totaling $239 million at December 31, 2013, of which $79 million and $8 million are related to storage capacity contracts with our affiliates, Young and Bear Creek, respectively. Our annual commitments under these agreements are $36 million in 2014, $28 million in 2015, $29 million in 2016, $29 million in 2017, $28 million in 2018 and $89 million in total thereafter.

Operating Leases

We lease property, facilities and equipment under various operating leases. Our minimum future annual rental commitments under our operating leases at December 31, 2013, are as follows (in millions):

2014	$	4
2015		4
2016		4
2017		4
2018		4
Thereafter		58
Total minimum lease payments	$	78

Rental expense on our operating leases for the year ended December 31, 2013 was $2 million and for each of the years ended December 31, 2012 and 2011 was $6 million and is reflected in "Operations and maintenance" expense on our Consolidated Statements of Income. While CIG and SNG hold the contractual obligations for the operating leases, the rent expense, which is considered a shared services cost and allocated to various KMI subsidiaries, is administered and funded by our parent, KMI. Our share of the rent expense is approximately 25% of the total KMI obligation.

10. Fair Value

The following table reflects the carrying amount and estimated fair values of our financial instruments (in millions):

	As of December 31,			
	2013		2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt, excluding other financing obligations (a)	$ 4,073	$ 4,441	$ 4,161	$ 4,895

(a) Our total other financing obligations were $175 million and $178 million as of December 31, 2013 and 2012, of which $6 million and $5 million was reported as "Current portion of debt" on our Consolidated Balance Sheets for each period.

We separate the fair values of our financial instruments into levels based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the estimated fair value. We estimated the above fair values of debt, excluding total other financing obligations, primarily based on quoted market prices for the same or similar issues, a Level 2 fair value measurement. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument and this change would be reflected at the end of the period in which the change occurs. During the years ended December 31, 2013 and 2012, there were no changes to the inputs and valuation techniques used to measure fair value of these instruments or the levels in which they were classified.

As of December 31, 2013 and 2012, the carrying amounts of cash and cash equivalents, short-term borrowings and current receivables and payables represent fair value because of the short-term nature of these instruments.

Interest Rate Derivatives

In May 2005, CPG entered into two interest rate swap agreements, which were designated as cash flow hedges and effectively converted 80% of the $266 million term loan from a floating interest rate to a fixed interest rate. In September 2012, in conjunction with the repayment of the CPG term loan, we settled the outstanding balance of our accrued liabilities related to our interest rate swaps of approximately $12 million. There was no ineffectiveness recognized for these interest rate swaps during the periods ended December 31, 2012 and 2011. The $12 million loss on termination of these interest rate derivatives included in "Accumulated other comprehensive income" was deferred as a regulatory asset pursuant to the accounting requirements for regulated operations. The regulatory asset is amortized over the term of the original debt issuance and included as "Interest expense, net" on our Consolidated Statements of Income.

11. Accounting for Regulatory Activities

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. As of December 31, 2013, the regulatory assets are being recovered as cost of service in our rates over a period of approximately one year to forty-two years. Below are the details of our regulatory assets and liabilities as of December 31 (in millions):

	2013	2012
Current regulatory assets		
Differences between gas retained and gas consumed in operations	$ 3	$ 27
Unamortized loss on sale of assets	13	13
Other	10	6
Total current regulatory assets	26	46
Non-current regulatory assets		
Taxes on capitalized funds used during construction	76	78
Unamortized loss on reacquired debt	30	41
Unamortized loss on sale of assets	10	23
Other	4	5
Total non-current regulatory assets	120	147
Total regulatory assets	$ 146	$ 193
Current regulatory liabilities		
Differences between gas retained and gas consumed in operations	$ 13	$ 9
Other	4	8
Total current regulatory liabilities	17	17
Non-current regulatory liabilities		
Property and plant retirements	8	8
Postretirement benefits	37	12
Other	15	13
Total non-current regulatory liabilities(a)	60	33
Total regulatory liabilities	$ 77	$ 50

(a) Included in “Other long-term liabilities and deferred credits” on our Consolidated Balance Sheets.

Our significant regulatory assets and liabilities include:

Difference between gas retained and gas consumed in operations

These amounts reflect the value of volumetric differences between gas retained and consumed in our operations. These amounts are not included in the rate base, but given our tariffs, are expected to be recovered from our customers or returned to our customers in subsequent fuel filing periods.

Taxes on capitalized funds used during construction

These regulatory asset balances were established to offset the deferred tax for the equity component of the allowance for funds used during the construction of long-lived assets. Taxes on capitalized funds used during construction and the offsetting deferred income taxes are included in the rate base and are recovered over the depreciable lives of the long lived asset to which they relate. These balances were established on our pipelines prior to their conversion to non-taxable entities.

Unamortized loss on reacquired debt

Amount represents the deferred and unamortized portion of losses on reacquired debt which are recovered through the cost of service over the original life of the debt issue, or in the case of refinanced debt, over the life of the new debt issue.

Unamortized loss on sale of assets

Amount represents the deferred and unamortized portion of the loss on our sale of offshore assets. In accordance with the settlement of SNG's rate case, the recovery of the total regulatory asset will occur over a three-year period ending on October 31, 2015. See Note 3 for further discussion regarding SNG's asset divestiture.

Postretirement benefits

Represents unrecognized gains or losses related to SNG's postretirement benefit plan. It also includes the differences between postretirement benefit amounts expensed and the amounts previously recovered in rates for CIG prior to its rate case settlement in August 2011. Prior to CIG's rate case settlement, the balances also included unrecognized gains and losses or changes in actuarial assumptions related to its postretirement benefit plan. As part of the CIG rate case settlement, CIG no longer includes these costs in its rates and during 2011 reclassified approximately $9 million to "Accumulated other comprehensive income."

Property and plant retirements

Amount represents the deferral of customer-funded amounts for costs of future asset retirements.

Regulatory Assets Amortization

Our amortization of the regulatory assets for 2013 totaled $31 million, which primarily consisted of (i) $12 million of the deferred losses on SNG's sale of offshore assets recorded as "Depreciation and amortization" and (ii) $11 million of the deferred losses on reacquired debt recorded as "Interest expense, net" on our Consolidated Statement of Income.

Rate Proceedings

WIC

The FERC initiated a rate proceeding on November 15, 2012 to investigate WIC's rates under Section 5 of the Natural Gas Act. On October 1, 2013, the FERC approved an uncontested Offer of Settlement filed in June 2013 by WIC to fully resolve FERC's rate investigation. WIC's approved settlement offer, agreed to by all active parties, provides for a two-phase, base tariff rate reduction on July 1, 2013 and January 1, 2014, as well as rate certainty for the parties during a three-year moratorium on new rates through July 1, 2016. The lower rates resulted in an annual revenue reduction of approximately $4 million in 2013 and are estimated to result in an additional $12 million reduction in 2014. The FERC order approving the uncontested settlement became effective November 1, 2013, and in December 2013 WIC made the rate refunds pursuant to the settlement.

SNG

On January 31, 2013, the FERC approved SNG's request to amend its January 2010 rate settlement with its customers. The amendment extended the required filing date for SNG's rate case from February 28, 2013 to no later than May 31, 2013. On May 2, 2013, SNG filed a comprehensive settlement with its customers to resolve all matters relating to its rates. The FERC approved the comprehensive settlement on July 12, 2013. Under the settlement, customers must extend all firm service agreements through August 31, 2016, and SNG cannot file a Section 4 rate case to be effective earlier than September 1, 2016. The settlement also includes a two-phase reduction in rates. The first phase, effective September 1, 2013, resulted in an approximately $11 million revenue reduction for 2013 and an additional revenue reduction of approximately $23 million for 2014. The second phase, effective November 1, 2015, will result in an additional revenue reduction of approximately $2 million for 2015 and an additional revenue reduction of approximately $12 million in 2016. The settlement prohibits both SNG and its customers from requesting a change to SNG's rates during a three-year moratorium through August 31, 2016 and requires SNG to file a new rate case to be effective no later than September 1, 2018.

CIG

In August 2011, the FERC approved an uncontested pre-filing settlement of a rate case required under the terms of a previous settlement. The settlement generally provides for (i) our current tariff rates to continue until our next general rate case which will be effective no earlier than October 1, 2014 but no later than October 1, 2016, (ii) contract extensions to March 2016, (iii) a revenue sharing mechanism with certain of our customers for certain revenues above annual threshold amounts and (iv) a revenue surcharge mechanism with certain of our customers to charge for certain shortfalls of revenue less than an annual threshold amount.

12. Transactions with Major Customers

Our non-affiliate trade accounts receivable as of December 31, 2013 and 2012 were $143 million and $148 million, respectively. We had $1 million of other non-affiliate accounts receivable as of December 31, 2013 and none as of December 31, 2012. Our affiliate receivables are discussed in Note 8.

The following table shows customers with revenues greater than 10% of our operating revenues, which we refer to as major customers, for each of the three years ended December 31 (in millions):

	2013	2012	2011
Shell Oil Company and subsidiaries	$ 220	$ 220	$ 221
PSCo and subsidiary	170	169	170
AGL Resources and subsidiaries	155	161	163

At December 31, 2013, we have transportation and storage agreements with PSCo for capacity on High Plains through 2029 and Totem through 2040 each with annual firm revenue of $39 million.

13. Accounts Receivable Sales Program

We participated in accounts receivable sales programs where we sold receivables in their entirety to a third party financial institution (through wholly-owned special purpose entities). On June 20, 2012, we terminated the accounts receivable sales programs and paid $44 million to the third-party financial institution, which consisted of sales proceeds received up front and servicing fees. The sale of these accounts receivable (which were short-term assets that generally settled within 60 days) qualified for sale accounting. The third party financial institution involved in these accounts receivable sales programs acquired interests in various financial assets and issued commercial paper to fund those acquisitions. We did not consolidate the third party financial institution because we did not have the power to control, direct or exert significant influence over its overall activities since our receivables did not comprise a significant portion of its operations.

In connection with our accounts receivable sales, we received a portion of the sales proceeds up front and received an additional amount upon the collection of the underlying receivables, which we referred to as a deferred purchase price. During 2012, we sold $418 million of accounts receivable to the third-party financial institution, for which we received $242 million of cash up front and had a deferred purchase price of $176 million. We received $191 million of cash when the underlying receivables were collected during 2012. Losses recognized on the sale of accounts receivable were immaterial for the years ended December 31, 2012 and 2011. There were no balances outstanding as of December 31, 2012 since all balances were settled in June 2012 when the accounts receivable sales programs were terminated.

The deferred purchase price related to the accounts receivable sold was reflected as "Accounts receivable, net" on our Consolidated Balance Sheets. Because the cash received up front and the deferred purchase price related to the sale or ultimate collection of the underlying receivables, and were not subject to significant other risks given their short term nature, we reflected all cash flows under the accounts receivable sales programs as "Cash Provided by Operating Activities" on our Statements of Cash Flows. Under the accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the years ended December 31, 2012 and 2011.

Supplemental Selected Quarterly Financial Information (Unaudited)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In Millions, Except Per Units Amounts)			
2013				
Revenues	$ 386	$ 359	$ 369	$ 391
Operating income(a)	246	209	212	228
Earnings from equity investments	3	3	3	4
Net income	174	136	141	159
Net income attributable to El Paso Pipeline Partners, L.P.	174	136	141	159
Limited Partners’ Net Income per Unit	0.58	0.40	0.40	0.48
2012				
Revenues	$ 390	$ 367	$ 368	$ 390
Operating income	222	173	220	248
Earnings from equity investments	3	4	4	3
Net income	155	105	151	178
Net income attributable to noncontrolling interests	(6)	(4)	—	—
Net income attributable to El Paso Pipeline Partners, L.P.	149	101	151	178
Limited Partners’ Net Income per Unit	0.54	0.44	0.55	0.62

(a) For the first and second quarter of 2013, amounts were recast for the amortization of the deferred losses on the sale of SNG's offshore assets, which is currently included in Depreciation and amortization on the Consolidated Statements of Income. See Note 3, "Acquisitions and Divestitures" for further discussion.

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.

EL PASO PIPELINE PARTNERS, L.P.
Registrant (a Delaware Limited Partnership)

By: **EL PASO PIPELINE GP COMPANY, L.L.C.**
Its sole General Partner

By: /s/ DAVID P. MICHELS
David P. Michels,
Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: February 19, 2014

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

Signature	Title	Date
/s/ DAVID P. MICHELS David P. Michels	Vice President and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. (principal financial and accounting officer)	February 19, 2014
/s/ RICHARD D. KINDER Richard D. Kinder	Director, Chairman and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C. (principal executive officer)	February 19, 2014
/s/ STEVEN J. KEAN Steven J. Kean	Director, President and Chief Operating Officer of El Paso Pipeline GP Company, L.L.C.	February 19, 2014
/s/ THOMAS A. MARTIN Thomas A. Martin	Director and Vice President (President, Natural Gas Pipelines) of El Paso Pipeline GP Company, L.L.C.	February 19, 2014
/s/ RONALD L. KUEHN JR. Ronald L. Kuehn, Jr.	Director of El Paso Pipeline GP Company, L.L.C.	February 19, 2014
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director of El Paso Pipeline GP Company, L.L.C.	February 19, 2014
/s/ WILLIAM A. SMITH William A. Smith	Director of El Paso Pipeline GP Company, L.L.C.	February 19, 2014

Exhibit 12

EL PASO PIPELINE PARTNERS, L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(In Millions, Except For Ratio)

	Year Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Earnings:					
Pre-tax income from continuing operations before adjustment for noncontrolling interest and equity earnings per statements of income	597	575	590	652	567
Add:					
Fixed charges	303	296	271	213	170
Distributed income of equity investees	11	13	15	22	14
Less:					
Allowance for funds used during construction (AFUDC)	(1)	(1)	(2)	(11)	(24)
Income as adjusted	$ 910	$ 883	$ 874	$ 876	$ 727
Fixed charges:					
Interest expense, net per statements of income (includes amortization of debt discount, premium and debt issuance costs; excludes AFUDC)	$ 301	$ 294	$ 269	$ 210	$ 167
Add:					
Portion of rents representative of the interest factor	2	2	2	3	3
Fixed charges	$ 303	$ 296	$ 271	$ 213	$ 170
Ratio of earnings to fixed charges	3.0	3.0	3.2	4.1	4.3

Exhibit 21

El Paso Pipeline Partners, L.P.

Ownership List as of December 31, 2013

Company Name	Jurisdiction of Incorporation	% Held
El Paso Pipeline Partners, L.P.		
El Paso Pipeline Partners Operating Company, L.L.C	Delaware	100
Elba Express Company, L.L.C.	Delaware	100
Colorado Interstate Gas Company, L.L.C.	Delaware	100
Colorado Interstate Issuing Corporation	Delaware	100
WYCO Development LLC	Colorado	50
Southern Natural Gas Company, L. L.C.	Delaware	100
Bear Creek Storage Company, L.L.C.	Louisiana	50
Southern Natural Issuing Corporation	Delaware	100
Southern LNG Company, L.L.C.	Delaware	100
Wyoming Interstate Company, L.L.C.	Delaware	100
Cheyenne Plains Gas Pipeline Company L.L.C	Delaware	100
Southern Liquefaction Company, LLC	Delaware	100
Elba Liquefaction Company, L.L.C.	Delaware	51

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-147940) and Form S-3 (Nos. 333-187547 and 333-186887) of El Paso Pipeline Partners, L.P. of our report dated February 19, 2014 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 19, 2014

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

1) Registration Statement (Form S-8, No. 333-147940) pertaining to the Long-Term Incentive Plan of El Paso Pipeline Partners, L.P.,
2) Registration Statement (Form S-3, No. 333-186887), and
3) Registration Statement (Form S-3, No. 333-187547)

of El Paso Pipeline Partners, L.P. and El Paso Pipeline Partners Operating Company, L.L.C. and in the related prospectus of our report dated February 26, 2013, with respect to the consolidated financial statements of El Paso Pipeline Partners, L.P. included in this Annual Report (Form 10-K) for the year ended December 31, 2013.

/s/ Ernst & Young LLP

Houston, Texas

February 19, 2014

Exhibit 31.1

EL PASO PIPELINE PARTNERS, L.P.
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Richard D. Kinder, certify that:

1. I have reviewed this Annual Report on Form 10-K of El Paso Pipeline Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2014

/s/ Richard D. Kinder
Richard D. Kinder
Chief Executive Officer of El Paso GP Company, L.L.C.
the General Partner of El Paso Pipeline Partners, L.P.

Exhibit 31.2

EL PASO PIPELINE PARTNERS, L.P.
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David P. Michels, certify that:

1. I have reviewed this Annual Report on Form 10-K of El Paso Pipeline Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States;
   (c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
   (d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 19, 2014

/s/ David P. Michels

David P. Michels
Vice President and Chief Financial Officer of El Paso GP Company, L.L.C. the General Partner of El Paso Pipeline Partners, L.P.

Exhibit 32.1

EL PASO PIPELINE PARTNERS, L.P.
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of El Paso Pipeline Partners, L.P. (the "Company") for the yearly period ending December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Richard D. Kinder

Richard D. Kinder
Chief Executive Officer of El Paso GP Company, L.L.C.
the General Partner of El Paso Pipeline Partners, L.P.

Date: February 19, 2014

Exhibit 32.2

EL PASO PIPELINE PARTNERS, L.P.
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of El Paso Pipeline Partners, L.P. (the "Company") for the yearly period ending December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David P. Michels

David P. Michels
Vice President and Chief Financial Officer of El Paso GP Company, L.L.C. the General Partner of El Paso Pipeline Partners, L.P.

Date: February 19, 2014