Williams Partners L.P.
Form 10-Q
July 31, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended June 30, 2014
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 1-32599

WILLIAMS PARTNERS L.P.
(Exact name of registrant as specified in its charter)

DELAWARE	20-2485124
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

ONE WILLIAMS CENTER	
TULSA, OKLAHOMA	74172-0172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (918) 573-2000
NO CHANGE

(Former name, former address and former fiscal year, if changed since last report)

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 þ 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

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

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨
		(Do not check if a smaller reporting company)	

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

The registrant had 438,625,699 common units and 26,034,437 Class D units outstanding as of July 30, 2014.

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Certain matters contained in this document include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this document that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "proposed," "goals," " "planned," "potential," "projects," "scheduled," "will," "assumes," "guidance," "outlook," "in service date" or other similar ex

These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- The levels of cash distributions to unitholders;
- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;

- Business strategy;
- Cash flow from operations or results of operations;
- Seasonality of certain business components;
- Natural gas, natural gas liquids, and olefins prices, supply and demand;
- Demand for our services;
- The proposed merger (the Proposed Merger) of Access Midstream Partners, L.P. (ACMP) and us.

Forward-looking statements are based on numerous assumptions, uncertainties, and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- The structure, terms, timing and approval of the Proposed Merger, as to be negotiated by each of our and ACMP's conflicts committees;
- Whether we have sufficient cash from operations to enable us to pay current and expected levels of cash distributions, if any, following establishment of cash reserves and payment of fees and expenses, including payments to our general partner;
- Availability of supplies, market demand, and volatility of prices;
- Inflation, interest rates, fluctuation in foreign exchange rates, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors and the effects of competition;
- Whether we are able to successfully identify, evaluate and execute investment opportunities;
- Our ability to acquire new businesses and assets and successfully integrate those operations and assets into our existing businesses, as well as successfully expand our facilities;
- Development of alternative energy sources;
- The impact of operational and development hazards and unforeseen interruptions;
- Our ability to recover expected insurance proceeds related to the Geismar plant;
- Costs of, changes in, or the results of laws, government regulations (including safety and environmental regulations), environmental liabilities, litigation and rate proceedings;
- Our allocated costs for defined benefit pension plans and other postretirement benefit plans sponsored by our affiliates;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;

- Our exposure to the credit risks of our customers and counterparties;
- Risks related to financing, including restrictions stemming from our debt agreements, future changes in our credit ratings, and the availability and cost of capital;
- The amount of cash distributions from and capital requirements of our investments and joint ventures in which we participate;
- Risks associated with weather and natural phenomena, including climate conditions;
- Acts of terrorism, including cybersecurity threats and related disruptions;
- Additional risks described in our filings with the Securities and Exchange Commission.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend 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.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this document. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2013, and Part II, Item 1A. Risk Factors of this Form 10-Q.

DEFINITIONS

The following is a listing of certain abbreviations, acronyms and other industry terminology used throughout this Form 10-Q.

Measurements:
Barrel: One barrel of petroleum products that equals 42 U.S. gallons
Bcf : One billion cubic feet of natural gas
Bcf/d: One billion cubic feet of natural gas per day
British Thermal Unit (Btu): A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
Dekatherms (Dth): A unit of energy equal to one million British thermal units
Mbbls/d: One thousand barrels per day
Mdth/d: One thousand dekatherms per day
MMcf/d: One million cubic feet per day
Consolidated Entities:
Constitution: Constitution Pipeline Company, LLC
Gulfstar One: Gulfstar One LLC
Northwest Pipeline: Northwest Pipeline, LLC
Transco: Transcontinental Gas Pipe Line Company, LLC
Partially Owned Entities: Entities in which we do not own a 100 percent ownership interest and which we account for as an equity investment, including principally the following:
Aux Sable: Aux Sable Liquid Products LP
Caiman II: Caiman Energy II, LLC
Discovery: Discovery Producer Services LLC
Gulfstream: Gulfstream Natural Gas System, L.L.C.
Laurel Mountain: Laurel Mountain Midstream, LLC
OPPL: Overland Pass Pipeline Company LLC
Government and Regulatory:
EPA: Environmental Protection Agency
FERC: Federal Energy Regulatory Commission
Other:
B/B Splitter: Butylene/Butane splitter
RGP Splitter: Refinery grade propylene splitter
IDR: Incentive distribution right
NGLs: Natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels, and gasoline additives, among other applications
NGL margins: NGL revenues less Btu replacement cost, plant fuel, transportation, and fractionation

PART I – FINANCIAL INFORMATION

Williams Partners L.P.
Consolidated Statement of Comprehensive Income
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions, except per-unit amounts)			
Revenues:				
Service revenues	$763	$717	$1,526	$1,419
Product sales	853	1,046	1,783	2,150
Total revenues	1,616	1,763	3,309	3,569
Costs and expenses:				
Product costs	724	801	1,493	1,591
Operating and maintenance expenses	251	289	499	546
Depreciation and amortization expenses	207	191	415	387
Selling, general, and administrative expenses	132	131	262	261
Net insurance recoveries – Geismar Incident	(42)	—	(161)	—
Other (income) expense – net	27	4	44	5
Total costs and expenses	1,299	1,416	2,552	2,790
Operating income	317	347	757	779
Equity earnings (losses)	32	35	55	53
Interest incurred	(142)	(118)	(273)	(236)
Interest capitalized	25	22	50	44
Other income (expense) – net	7	7	10	12
Income before income taxes	239	293	599	652
Provision for income taxes	5	21	13	36
Net income	234	272	586	616
Less: Net income attributable to noncontrolling interests	2	1	2	1
Net income attributable to controlling interests	$232	$271	$584	$615
Allocation of net income for calculation of earnings per common unit:				
Net income attributable to controlling interests	$232	$271	$584	$615
Allocation of net income to general partner	167	141	347	283
Allocation of net income to Class D units	18	—	32	—
Allocation of net income to common units	$47	$130	$205	$332
Basic and diluted earnings per common unit	$.11	$.31	$.47	$.81
Weighted average number of common units outstanding (thousands)	438,626	413,901	438,626	407,968
Cash distributions per common unit	$.9165	$.8625	$1.8210	$1.7100
Other comprehensive income (loss):				
Net unrealized gain (loss) from derivative instruments	$—	$1	$—	$1
Foreign currency translation adjustments	39	(26)	5	(45)
Other comprehensive income (loss)	39	(25)	5	(44)
Comprehensive income	$273	$247	$591	$572
Less: Comprehensive income attributable to noncontrolling interests	2	1	2	1
Comprehensive income attributable to controlling interests	$271	$246	$589	$571

See accompanying notes.

Williams Partners L.P.
Consolidated Balance Sheet
(Unaudited)

	June 30, 2014	December 31, 2013
	(Dollars in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$716	$110
Trade accounts and notes receivable, net	544	568
Inventories	276	194
Other current assets	182	96
Total current assets	1,718	968
Investments	2,375	2,187
Property, plant, and equipment, at cost	26,602	25,062
Accumulated depreciation	(7,752)	(7,437)
Property, plant, and equipment – net	18,850	17,625
Goodwill	646	646
Other intangible assets, net of amortization	1,614	1,642
Regulatory assets, deferred charges, and other	535	503
Total assets	$25,738	$23,571
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$945	$889
Affiliate	139	104
Accrued interest	137	115
Asset retirement obligations	68	64
Other accrued liabilities	226	375
Long-term debt due within one year	750	—
Commercial paper	—	225
Total current liabilities	2,265	1,772
Long-term debt	11,047	9,057
Asset retirement obligations	535	497
Deferred income taxes	127	117
Regulatory liabilities, deferred income, and other	617	561
Contingent liabilities (Note 9)		
Equity:		
Partners' equity:		
Common units (438,625,699 units outstanding at June 30, 2014 and December 31, 2013)	11,150	11,596
Class D units (26,034,437 units outstanding at June 30, 2014)	866	—
General partner	(1,498)	(536)
Accumulated other comprehensive income (loss)	96	92
Total partners' equity	10,614	11,152
Noncontrolling interests in consolidated subsidiaries	533	415
Total equity	11,147	11,567
Total liabilities and equity	$25,738	$23,571

See accompanying notes.

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Williams Partners L.P.
Consolidated Statement of Changes in Equity
(Unaudited)

	Williams Partners L.P. Limited Partners						
	Common Units	Class D Units	General Partner	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(Millions)						
Balance – December 31, 2013	$11,596	$—	$(536)	$ 92	$11,152	$ 415	$11,567
Net income	245	2	337	—	584	2	586
Other comprehensive income (loss)	—	—	—	5	5	—	5
Cash distributions (Note 3)	(788)	—	(334)	—	(1,122)	—	(1,122)
Distributions to The Williams Companies, Inc. - net	—	—	(11)	—	(11)	—	(11)
Issuance of Class D units in common control transaction (Note 1)	—	961	(961)	—	—	—	—
Beneficial conversion feature of Class D units	117	(117)	—	—	—	—	—
Amortization of beneficial conversion feature of Class D units	(20)	20	—	—	—	—	—
Contributions from general partner	—	—	7	—	7	—	7
Contributions from noncontrolling interests	—	—	—	—	—	116	116
Other	—	—	—	(1)	(1)	—	(1)
Balance – June 30, 2014	$11,150	$866	$(1,498)	$ 96	$10,614	$ 533	$11,147

See accompanying notes.

Williams Partners L.P.
Consolidated Statement of Cash Flows
(Unaudited)

	Six months ended June 30, 2014	2013
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$586	$616
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	415	387
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	23	37
Inventories	(81)	2
Other current assets and deferred charges	(37)	(10)
Accounts payable	(63)	(18)
Accrued liabilities	32	62
Affiliate accounts receivable and payable – net	34	3
Other, including changes in noncurrent assets and liabilities	5	96
Net cash provided by operating activities	914	1,175
FINANCING ACTIVITIES:		
Proceeds from (payments of) commercial paper – net	(226)	710
Proceeds from long-term debt	2,740	1,705
Payments of long-term debt	—	(2,080)
Proceeds from sales of common units	—	760
General partner contributions	7	24
Distributions to limited partners and general partner	(1,122)	(915)
Contributions from noncontrolling interests	116	251
Contributions from The Williams Companies, Inc. – net	45	103
Other – net	(9)	12
Net cash provided by financing activities	1,551	570
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(1,667)	(1,494)
Net proceeds from dispositions	28	2
Purchase of businesses from affiliates	(56)	25
Purchases of and contributions to equity-method investments	(231)	(182)
Other – net	67	(5)
Net cash used by investing activities	(1,859)	(1,654)
Increase (decrease) in cash and cash equivalents	606	91
Cash and cash equivalents at beginning of period	110	82
Cash and cash equivalents at end of period	$716	$173

See accompanying notes.

Williams Partners L.P.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1 – General and Basis of Presentation

General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 19, 2014. The accompanying unaudited financial statements include all normal recurring adjustments and others that, in the opinion of management, are necessary to present fairly our interim financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Unless the context clearly indicates otherwise, references in this report to “we,” “our,” “us,” or similar language refer to Williams Partners L.P. and its subsidiaries.

We are a publicly traded Delaware limited partnership. Williams Partners GP LLC, a Delaware limited liability company wholly owned by The Williams Companies, Inc. (Williams), serves as our general partner. As of June 30, 2014, Williams owns an approximate 64 percent limited partner interest, a 2 percent general partner interest and incentive distribution rights (IDRs) in us. All of our activities are conducted through Williams Partners Operating LLC, an operating limited liability company (wholly owned by us).

Description of Business

Our operations are located in North America and are organized into the following reportable segments: Northeast G&P, Atlantic-Gulf, West, and NGL & Petchem Services.

Northeast G&P is comprised of our midstream gathering and processing businesses in the Marcellus and Utica shale regions, as well as a 51 percent equity investment in Laurel Mountain Midstream, LLC (Laurel Mountain) and a 58 percent equity investment in Caiman Energy II, LLC (Caiman II).

Atlantic-Gulf is comprised of our interstate natural gas pipeline, Transcontinental Gas Pipe Line Company, LLC (Transco), and significant natural gas gathering and processing and crude production handling and transportation in the Gulf Coast region, as well as a 50 percent equity investment in Gulfstream Natural Gas System, L.L.C., a 41 percent interest in Constitution Pipeline Company, LLC (Constitution) (a consolidated entity), and a 60 percent equity investment in Discovery Producer Services LLC.

West is comprised of our interstate natural gas pipeline, Northwest Pipeline LLC, and our gathering, processing and treating operations in New Mexico, Colorado, and Wyoming.

NGL & Petchem Services is comprised of our 83.3 percent undivided interest in an olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf Coast region, an oil sands offgas processing plant located near Fort McMurray, Alberta, and a natural gas liquid (NGL)/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta. This segment also includes our NGL and natural gas marketing business, storage facilities and an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, and a 50 percent equity investment in Overland Pass Pipeline, LLC.

Notes (Continued)

Basis of Presentation

Canada Acquisition

We acquired certain Canadian operations in February 2014 from Williams (Canada Acquisition) for total consideration of $56 million of cash (including a $31 million post-closing adjustment paid in the second quarter), 25,577,521 Class D limited-partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. In lieu of cash distributions, the Class D units receive quarterly distributions of additional paid-in-kind Class D units. All outstanding Class D units will be convertible to common units beginning in the first quarter of 2016. The contribution agreement governing the Canada Acquisition provides that we can issue additional Class D units to Williams on a quarterly basis through 2015 for up to a total of $200 million in cash for the purpose of funding certain facility expansions. At June 30, 2014, no additional Class D units have been issued to Williams under this provision. This common control acquisition was treated similar to a pooling of interests whereby the historical results of operations were combined with ours for all periods presented. These Canadian operations are reported in our NGL & Petchem Services segment.

The Canadian operations previously participated in Williams' cash management program under a credit agreement with Williams. Net changes in amounts due to/from Williams prior to the Canada Acquisition, along with the cash consideration paid for the Canada Acquisition, are reflected within Distributions to The Williams Companies, Inc. - net within the Consolidated Statement of Changes in Equity.

Prior period amounts and disclosures have been recast for this transaction. The effect of recasting our financial statements to account for this transaction increased net income for the three and six months ended June 30, 2013, by $15 million and $38 million, respectively. This acquisition does not impact historical earnings per unit as pre-acquisition earnings were allocated to our general partner.

Certain of our foreign subsidiaries use the Canadian dollar as their functional currency. Assets and liabilities of such foreign subsidiaries are translated at the spot rate in effect at the applicable reporting date, and the statements of income are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of Accumulated other comprehensive income (loss) (AOCI).

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates when the transactions are settled result in transaction gains and losses which are reflected in the Consolidated Statement of Comprehensive Income.

Accounting standards issued but not yet adopted

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09 establishing Accounting Standards Codification Topic 606, "Revenue from Contracts with Customers" (ASC 606). ASC 606 establishes a comprehensive new revenue recognition model designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to be entitled to receive in exchange for those goods or services and requires significantly enhanced revenue disclosures. The standard is effective for annual reporting periods beginning after December 15, 2016, and interim periods within the reporting period. Accordingly, we will adopt this standard in the first quarter of 2017. ASC 606 allows either full retrospective or modified retrospective transition and early adoption is not permitted. We are currently evaluating the impact of this new standard on our consolidated financial statements.

Accumulated Other Comprehensive Income (Loss)

AOCI is substantially comprised of foreign currency translation adjustments. These adjustments did not impact Net income in any of the periods presented.

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Notes (Continued)

Note 2 – Variable Interest Entities

Consolidated VIEs

As of June 30, 2014, we consolidate the following variable interest entities (VIEs):

Gulfstar One

We own a 51 percent interest in Gulfstar One LLC (Gulfstar One), a subsidiary that, due to certain risk-sharing provisions in its customer contracts, is a VIE. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Gulfstar One's economic performance. We, as construction agent for Gulfstar One, designed, constructed, and are installing a proprietary floating-production system, Gulfstar FPS™, and associated pipelines which will initially provide production handling and gathering services for the Tubular Bells oil and gas discovery in the eastern deepwater Gulf of Mexico. The project is expected to be in service in the third quarter of 2014. We have received certain advance payments from the producer customers and are committed to the producer customers to construct this system. The current estimate of the total remaining construction costs is less than $50 million, which we expect will be funded with capital contributions from us and the other equity partner on a proportional basis. During the second quarter of 2014, we provided a temporary advance to Gulfstar One of $128 million to permit ongoing construction pending further expected contributions from our partner. The producer customers will be responsible for the firm price of building the facilities if they do not develop the offshore oil and gas fields to be connected to Gulfstar One.

In July 2014, our partner elected to participate in the funding of an expansion of Gulfstar One that will provide production handling, gathering, and processing services for the Gunflint oil and gas discovery in the eastern deepwater Gulf of Mexico. The expansion project is expected to be in service in the first quarter of 2016. The current estimate of the total remaining construction costs for the Gunflint project is less than $134 million which we expect will be funded with capital contributions from us and the other equity partner on a proportional basis.

Constitution

We own a 41 percent interest in Constitution, a subsidiary that, due to shipper fixed-payment commitments under its firm transportation contracts, is a VIE. We are the primary beneficiary because we have the power to direct the activities that most significantly impact Constitution's economic performance. We, as construction agent for Constitution, are building a pipeline connecting our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and the Tennessee Gas Pipeline systems. We plan to place the project in service in late 2015 to 2016 and estimate the total remaining construction costs of the project to be approximately $575 million, which will be funded with capital contributions from us and the other equity partners, proportional to ownership interest.

Notes (Continued)

The following table presents amounts included in our Consolidated Balance Sheet that are for the use or obligation of these VIEs, which are joint projects in the development and construction phase:

	June 30, 2014 (Millions)	December 31, 2013	Classification
Assets (liabilities):			
Cash and cash equivalents	$78	$76	Cash and cash equivalents
Property, plant, and equipment	1,387	998	Property, plant, and equipment, at cost
Accounts payable	(120)	(120)	Accounts payable - trade
Construction retainage	(4)	(3)	Other accrued liabilities
Current deferred revenue	—	(10)	Other accrued liabilities
Asset retirement obligation	(30)	—	Asset retirement obligations, noncurrent
Noncurrent deferred revenue associated with customer advance payments	(130)	(115)	Regulatory liabilities, deferred income, and other

Nonconsolidated VIEs

We have also identified certain interests in VIEs for which we are not the primary beneficiary. These include:

Laurel Mountain

Our 51 percent-owned equity-method investment in Laurel Mountain is considered to be a VIE generally due to contractual provisions that transfer certain risks to customers. As decisions about the activities that most significantly impact the economic performance of this entity require a unanimous vote of all members, we are not the primary beneficiary. Our maximum exposure to loss is limited to the carrying value of this investment, which was $477 million at June 30, 2014.

Caiman II

During April 2014, Caiman II, a previously reported VIE, became able to finance its current activities without additional subordinated financial support due in part to its primary investee securing a revolving credit agreement with a third party. The total equity investment at risk of Caiman II is sufficient to finance its activities. As a result, Caiman II is no longer a VIE and continues to be reported as a 58 percent-owned equity-method investment.

Notes (Continued)

Note 3 – Allocation of Net Income and Distributions

The allocation of net income between our general partner and limited partners is as follows:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Allocation of net income to general partner:				
Net income	$234	$272	$586	$616
Net income applicable to pre-partnership operations allocated to general partner	—	(15)	(15)	(38)
Net income applicable to noncontrolling interests	(2)	(1)	(2)	(1)
Income subject to 2% allocation of general partner interest	232	256	569	577
General partner's share of net income	2%	2%	2%	2%
General partner's allocated share of net income before items directly allocable to general partner interest	4	5	11	11
Priority allocations, including incentive distributions, paid to general partner (1)	158	112	311	216
Pre-partnership net income allocated to general partner interest	—	15	15	38
Net income allocated to general partner	$162	$132	$337	$265
Net income	$234	$272	$586	$616
Net income allocated to general partner	162	132	337	265
Net income allocated to Class D limited partners (2)	18	—	22	—
Net income allocated to noncontrolling interests	2	1	2	1
Net income allocated to common limited partners (2)	$52	$139	$225	$350

(1) The net income allocated to the general partner's capital account reflects IDRs paid during the current reporting period. In the calculation of basic and diluted earnings per common unit, the net income allocated to the general partner includes IDRs pertaining to the current reporting period but paid in the subsequent period.

(2) The net income allocated to common and Class D limited partners includes $15 million and $20 million for the three and six months ended June 30, 2014, respectively, related to the amortization of the beneficial conversion feature associated with the Class D units.

We paid or have authorized payment of the following partnership cash distributions during 2013 and 2014 (in millions, except for per unit amounts):

			General Partner		
Payment Date	Per Unit Distribution	Common Units	2%	Incentive Distribution Rights	Total Cash Distribution
2/8/2013	$0.8275	$329	$9	$104	$442
5/10/2013	0.8475	351	10	112	473
8/09/2013	0.8625	357	11	121	489
11/12/2013	0.8775	385	11	46	442
2/13/2014	0.8925	392	11	153	556
5/9/2014	0.9045	396	12	158	566
8/8/2014 (1)	0.9165	402	12	163	577

(1) The Board of Directors of our general partner declared this $0.9165 per common unit cash distribution on July 21, 2014, to be paid on August 8, 2014, to unitholders of record at the close of business on August 1, 2014.

Notes (Continued)

The 2013 and 2014 cash distributions paid to our general partner in the table above have been reduced by $155 million resulting from the temporary waiver of IDRs associated with certain assets acquired in 2012 and an additional $90 million in IDRs waived by our general partner related to the third quarter 2013 distribution, to support our cash distribution metrics.

Class D Units

As previously mentioned (see Note 1 – General and Basis of Presentation), a portion of the total consideration for the Canada Acquisition was funded through the issuance of Class D units to an affiliate of our general partner, which are convertible to common units on a one-for-one basis beginning in the first quarter of 2016. The Class D units were issued at a discount to the market price of our common units, into which they are convertible. The discount represents a beneficial conversion feature and is reflected as an increase in the common unit capital account and a decrease in the Class D capital account on the Consolidated Statement of Changes in Equity. This discount is being amortized through the conversion date in the first quarter of 2016, resulting in an increase to the Class D capital account and a decrease to the common unit capital account.

Distributions

The Class D units are not entitled to cash distributions. Instead, prior to conversion into common units, the Class D units receive quarterly distributions of additional paid-in-kind Class D units no later than the applicable distribution date. With respect to the Class D units, the number of Class D units to be issued in connection with a Class D unit distribution is the quotient of the amount of the per-unit distribution declared for a common unit for the applicable distribution period multiplied by the number of Class D units outstanding as of the record date, divided by the volume-weighted average price of a common unit calculated over the consecutive 30-day trading period prior to the declaration of the quarterly distribution to common units. On May 9, 2014, we issued 456,916 Class D units as the paid-in-kind Class D distribution with respect to the first quarter 2014. On July 21, 2014, the Board of Directors of our general partner authorized the issuance of 441,070 Class D units as the paid-in-kind Class D distribution with respect to the second quarter, to be issued on August 8, 2014.

Earnings per unit

Basic and diluted earnings per limited partner unit are calculated using the two-class method. At June 30, 2014, Class D units are anti-dilutive and therefore not included in calculating diluted earnings per common unit.

Note 4 – Other Income and Expenses

The following table presents certain gains or losses reflected in Other (income) expense – net within Costs and expenses in our Consolidated Statement of Comprehensive Income:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Northeast G&P				
Impairment of certain equipment held for sale (see Note 8)	$17	$—	$17	$—
Atlantic-Gulf				
Amortization of regulatory assets associated with asset retirement obligations	8	5	17	7
Write-off of the Eminence abandonment regulatory asset not recoverable through rates	—	6	—	6
Insurance recoveries associated with the Eminence abandonment	—	(12)	—	(12)

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Notes (Continued)

Geismar Incident

On June 13, 2013, an explosion and fire occurred at our Geismar olefins plant. The fire was extinguished on the day of the incident. The incident (Geismar Incident) rendered the facility temporarily inoperable and resulted in significant human, financial, and operational effects.

We have substantial insurance coverage for repair and replacement costs, lost production, and additional expenses related to the incident as follows:

- Property damage and business interruption coverage with a combined per-occurrence limit of $500 million and retentions (deductibles) of $10 million per occurrence for property damage and a waiting period of 60 days per occurrence for business interruption;
- General liability coverage with per-occurrence and aggregate annual limits of $610 million and retentions (deductibles) of $2 million per occurrence;
- Workers' compensation coverage with statutory limits and retentions (deductibles) of $1 million total per occurrence.

During the three and six month periods ended June 30, 2014, we received $50 million and $175 million, respectively, of insurance recoveries related to the Geismar Incident. The three and six month periods ended June 30, 2014, also include $8 million and $14 million, respectively, of related covered insurable expenses incurred in excess of our retentions (deductibles). These amounts are reported within NGL & Petchem Services and reflected as net gains in Net insurance recoveries – Geismar Incident in the Consolidated Statement of Comprehensive Income.

The three and six month periods ended June 30, 2013, include $6 million of costs under our insurance deductibles reported in Operating and maintenance expenses in the Consolidated Statement of Comprehensive Income.

Note 5 – Provision for Income Taxes

The Provision for income taxes includes:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Current:				
State	$2	$(1)	$2	$2
Foreign	1	(6)	1	(4)
	3	(7)	3	(2)
Deferred:				
State	(1)	14	—	14
Foreign	3	14	10	24
	2	28	10	38
Total provision	$5	$21	$13	$36

The effective income tax rates for the total provision for the three and six months ended June 30, 2014 and 2013, are less than the federal statutory rate due to income not subject to U.S. federal tax, partially offset by taxes on foreign operations and the effect of Texas franchise tax. The 2013 state deferred provision includes $14 million related to the impact of a second-quarter Texas franchise tax law change.

Notes (Continued)

Note 6 – Inventories

	June 30, 2014	December 31, 2013
	(Millions)	
Natural gas liquids, olefins, and natural gas in underground storage	$195	$111
Materials, supplies, and other	81	83
	$276	$194

Note 7 – Debt and Banking Arrangements

Long-Term Debt

Issuances

On June 27, 2014, we completed a public offering of $750 million of 3.9 percent senior unsecured notes due 2025 and $500 million of 4.9 percent senior unsecured notes due 2045. We used a portion of the net proceeds to repay amounts outstanding under our commercial paper program and expect to utilize the remainder to fund capital expenditures and for general partnership purposes.

On March 4, 2014, we completed a public offering of $1 billion of 4.3 percent senior unsecured notes due 2024 and $500 million of 5.4 percent senior unsecured notes due 2044. We used the net proceeds to repay amounts outstanding under our commercial paper program, to fund capital expenditures, and for general partnership purposes.

Credit Facility

Letter of credit capacity under our $2.5 billion credit facility is $1.3 billion. At June 30, 2014, no letters of credit have been issued and no loans are outstanding under our credit facility. We issued letters of credit totaling $1 million as of June 30, 2014, under a certain bilateral bank agreement.

Notes (Continued)

Note 8 – Fair Value Measurements and Guarantee

The following table presents, by level within the fair value hierarchy, certain of our financial assets and liabilities. The carrying values of cash and cash equivalents, accounts receivable, commercial paper, and accounts payable approximate fair value because of the short-term nature of these instruments. Therefore, these assets and liabilities are not presented in the following table.

			Fair Value Measurements Using		
	Carrying Amount	Fair Value	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(Millions)				
Assets (liabilities) at June 30, 2014:					
Measured on a recurring basis:					
ARO Trust investments	$42	$42	$42	$—	$—
Energy derivatives assets not designated as hedging instruments	3	3	—	—	3
Energy derivatives liabilities not designated as hedging instruments	(2)	(2)	—	—	(2)
Additional disclosures:					
Notes receivable and other	7	7	2	5	—
Long-term debt, including current portion	(11,797)	(12,843)	—	(12,843)	—
Assets (liabilities) at December 31, 2013:					
Measured on a recurring basis:					
ARO Trust investments	$33	$33	$33	$—	$—
Energy derivatives assets not designated as hedging instruments	3	3	—	—	3
Energy derivatives liabilities not designated as hedging instruments	(3)	(3)	—	(1)	(2)
Additional disclosures:					
Notes receivable and other	7	7	1	6	—
Long-term debt	(9,057)	(9,581)	—	(9,581)	—

Fair Value Methods

We use the following methods and assumptions in estimating the fair value of our financial instruments:

Assets and liabilities measured at fair value on a recurring basis

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its rate case settlement, into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations. The ARO Trust invests in a portfolio of actively traded mutual funds that are measured at fair value on a recurring basis based on quoted prices in an active market, is classified as available-for-sale, and is reported in Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet. Both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Energy derivatives: Energy derivatives include commodity based exchange-traded contracts and over-the-counter (OTC) contracts, which consist of physical forwards, futures, and swaps that are measured at fair value on a recurring basis. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions. Energy derivatives

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Notes (Continued)

assets are reported in Other current assets and Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet. Energy derivatives liabilities are reported in Other accrued liabilities and Regulatory liabilities, deferred income, and other in the Consolidated Balance Sheet.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No transfers between Level 1 and Level 2 occurred during the six months ended June 30, 2014 or 2013.

Additional fair value disclosures

Notes receivable and other: The disclosed fair value of our notes receivable is primarily determined by an income approach which considers the underlying contract amounts and our assessment of our ability to recover these amounts. The current portion is reported in Trade accounts and notes receivable, net and the noncurrent portion is reported in Regulatory assets, deferred charges, and other in the Consolidated Balance Sheet.

Long-term debt: The disclosed fair value of our long-term debt is determined by a market approach using broker quoted indicative period-end bond prices. The quoted prices are based on observable transactions in less active markets for our debt or similar instruments.

Assets and liabilities measured at fair value on a nonrecurring basis

In second quarter 2014, we designated certain equipment within our Northeast G&P segment as held for sale. The estimated fair value (less cost to sell) of the equipment at June 30, 2014, is $46 million and is reported in Other current assets in the Consolidated Balance Sheet. The estimated fair value was determined by a market approach based on our analysis of information related to sales of similar pre-owned equipment in the principal market. This analysis resulted in an impairment charge of $17 million, recorded in Other (income) expense – net within Costs and expenses. This nonrecurring fair value measurement fell within Level 3 of the fair value hierarchy.

Guarantee

We are required by our revolving credit agreement to indemnify lenders for certain taxes required to be withheld from payments due to the lenders and for certain tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

Note 9 – Contingent Liabilities

Environmental Matters

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and remedial processes at certain sites, some of which we currently do not own. We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), and other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. As of June 30, 2014, we have accrued liabilities totaling $19 million for these matters, as discussed below. Our accrual reflects the most likely costs of cleanup, which are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. Certain assessment studies are still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Any incremental amount in excess of amounts currently accrued cannot be reasonably estimated at this time due to uncertainty about the actual number of contaminated sites ultimately identified, the actual amount and extent of contamination discovered and the final cleanup standards mandated by the EPA and other governmental authorities.

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Notes (Continued)

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. More recent rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, one hour nitrogen dioxide emission limits, and new air quality standards impacting storage vessels, pressure valves, and compressors. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyls, mercury, and other hazardous substances. These activities have involved the EPA and various state environmental authorities, resulting in our identification as a potentially responsible party at various Superfund waste sites. At June 30, 2014, we have accrued liabilities of $11 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At June 30, 2014, we have accrued liabilities totaling $8 million for these costs.

Geismar Incident

As a result of the previously discussed Geismar Incident, there were two fatalities, and numerous individuals (including affiliate employees and contractors) reported injuries, which varied from minor to serious. We are cooperating with the Chemical Safety Board and the EPA regarding their investigations of the Geismar Incident. On October 21, 2013, the EPA issued an Inspection Report pursuant to the Clean Air Act's Risk Management Program following its inspection of the facility on June 24 through 28, 2013. The report notes the EPA's preliminary determinations about the facility's documentation regarding process safety, process hazard analysis, as well as operating procedures, employee training, and other matters. On June 16, 2014, we received a request for information related to the Geismar Incident from the EPA under Section 114 of the Clean Air Act. We and the EPA continue to discuss preliminary determinations, and the EPA could issue penalties pertaining to final determinations. On December 11, 2013, the Occupational Safety and Health Administration (OSHA) issued citations in connection with its investigation of the June 13, 2013 incident, which included a Notice of Penalty for $99,000. We have settled the citations in principle with OSHA, but have not yet finalized a settlement agreement. On June 25, 2013, OSHA commenced a second inspection pursuant to its Refinery and Chemical National Emphasis Program (NEP). OSHA did not issue a citation to us in connection with this NEP inspection and there is a six-month statute of limitations for violation of the Occupational Safety and Health Act of 1970 or regulations promulgated under such act. On June 28, 2013, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order & Notice of Potential Penalty to Williams Olefins, L.L.C. that consolidates claims of unpermitted emissions and other deviations under the Clean Air Act that the parties had been negotiating since 2010 and alleged unpermitted emissions arising from the Geismar Incident. Negotiations with the LDEQ are ongoing. Any potential fines and penalties from these agencies would not be covered by our insurance policy. Additionally, multiple lawsuits, including class actions for alleged offsite impacts, property damage, customer claims, and personal injury, have been filed against various of our subsidiaries.

Due to the ongoing investigation into the cause of the incident, and the limited information available associated with the filed lawsuits, which generally do not specify any amounts for claimed damages, we cannot reasonably estimate a range of potential loss related to these contingencies at this time.

Transco 2012 Rate Case

On August 31, 2012, Transco submitted to the Federal Energy Regulatory Commission (FERC) a general rate filing principally designed to recover increased costs and to comply with the terms of the settlement in its prior rate proceedings. The new rates became effective March 1, 2013, subject to refund and the outcome of the hearing. On August 27, 2013, Transco filed a stipulation and agreement with the FERC proposing to resolve all issues in this proceeding without the need for a hearing (Agreement). On December 6, 2013, the FERC issued an order approving the Agreement without modifications. Pursuant to its terms, the Agreement became effective March 1, 2014. We paid

$118 million of rate refunds on April 18, 2014.

Notes (Continued)

Other
In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.
Summary
We estimate that for all matters for which we are able to reasonably estimate a range of loss, including those noted above and others that are not individually significant, our aggregate reasonably possible losses beyond amounts accrued for all of our contingent liabilities are immaterial to our expected future annual results of operations, liquidity, and financial position. These calculations have been made without consideration of any potential recovery from third parties. We disclose all significant matters for which we are unable to reasonably estimate a range of possible loss.
Note 10 – Segment Disclosures
Our reportable segments are Northeast G&P, Atlantic-Gulf, West, and NGL & Petchem Services. (See Note 1 – General and Basis of Presentation.)
Performance Measurement
We currently evaluate segment operating performance based on Segment profit (loss) from operations, which includes Segment revenues from external and internal customers, segment costs and expenses, Equity earnings (losses), and Income (loss) from investments. General corporate expenses represent Selling, general, and administrative expenses that are not allocated to our segments. Intersegment revenues primarily represent the sale of NGLs from our natural gas processing plants to our marketing business and are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Notes (Continued)

The following table reflects the reconciliation of Segment revenues and Segment profit (loss) to Total revenues and Operating income as reported in the Consolidated Statement of Comprehensive Income.

	Northeast G&P	Atlantic-Gulf	West	NGL & Petchem Services	Eliminations	Total
	(Millions)					
Three months ended June 30, 2014						
Segment revenues:						
Service revenues						
External	$107	$363	$261	$32	$—	$763
Internal	—	1	—	—	(1)	—
Total service revenues	107	364	261	32	(1)	763
Product sales						
External	37	112	20	684	—	853
Internal	—	97	112	67	(276)	—
Total product sales	37	209	132	751	(276)	853
Total revenues	$144	$573	$393	$783	$(277)	$1,616
Segment profit (loss)	$15	$168	$152	$58		$393
Less equity earnings (losses)	10	16	—	6		32
Segment operating income (loss)	$5	$152	$152	$52		361
General corporate expenses						(44)
Operating income						$317
Three months ended June 30, 2013						
Segment revenues:						
Service revenues						
External	$78	$349	$260	$30	$—	$717
Internal	—	4	—	—	(4)	—
Total service revenues	78	353	260	30	(4)	717
Product sales						
External	35	220	11	780	—	1,046
Internal	—	29	180	83	(292)	—
Total product sales	35	249	191	863	(292)	1,046
Total revenues	$113	$602	$451	$893	$(296)	$1,763
Segment profit (loss)	$12	$152	$162	$101		$427
Less:						
Equity earnings (losses)	7	20	—	8		35
Income (loss) from investments	—	—	—	(1)		(1)
Segment operating income (loss)	$5	$132	$162	$94		393
General corporate expenses						(46)
Operating income						$347
Six months ended June 30, 2014						
Segment revenues:						
Service revenues						
External	$206	$741	$517	$62	$—	$1,526

Internal	—	2	—	—	(2)	—
Total service revenues	206	743	517	62	(2)	1,526
Product sales						
External	97	264	39	1,383	—	1,783
Internal	—	166	238	143	(547)	—
Total product sales	97	430	277	1,526	(547)	1,783
Total revenues	$303	$1,173	$794	$1,588	$(549)	$3,309
Segment profit (loss)	$21	$333	$317	$225		$896
Less equity earnings (losses)	11	31	—	13		55
Segment operating income (loss)	$10	$302	$317	$212		841
General corporate expenses						(84)
Operating income						$757

Notes (Continued)

	Northeast G&P	Atlantic-Gulf	West	NGL & Petchem Services	Eliminations	Total
	(Millions)					
Six months ended June 30, 2013						
Segment revenues:						
Service revenues						
External	$141	$703	$518	$57	$—	$1,419
Internal	—	8	—	—	(8)	—
Total service revenues	141	711	518	57	(8)	1,419
Product sales						
External	55	425	37	1,633	—	2,150
Internal	—	55	353	161	(569)	—
Total product sales	55	480	390	1,794	(569)	2,150
Total revenues	$196	$1,191	$908	$1,851	$(577)	$3,569
Segment profit (loss)	$3	$311	$348	$259		$921
Less:						
Equity earnings (losses)	4	36	—	13		53
Income (loss) from investments	—	—	—	(2)		(2)
Segment operating income (loss)	$(1)	$275	$348	$248		870
General corporate expenses						(91)
Operating income						$779

The following table reflects Total assets by reportable segment.

	Total Assets June 30, 2014	December 31, 2013
	(Millions)	
Northeast G&P	$6,908	$6,229
Atlantic-Gulf	10,513	10,007
West	4,704	4,767
NGL & Petchem Services	3,452	3,035
Other corporate assets	962	147
Eliminations (1)	(801)	(614)
Total	$25,738	$23,571

(1) Eliminations primarily relate to the intercompany accounts receivable generated by our cash management program.

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

We are an energy infrastructure company focused on connecting North America’s significant hydrocarbon resource plays to growing markets for natural gas, NGLs, and olefins through our gas pipeline and midstream businesses.

Our interstate natural gas pipeline strategy is to create value by maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets. Our gas pipeline businesses’ interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC’s ratemaking process. Changes in commodity prices and volumes transported have limited near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

The ongoing strategy of our midstream operations is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers. These services include natural gas gathering, processing and treating, NGL fractionation and transportation, crude oil production handling and transportation, olefin production, marketing services for NGL, oil and natural gas, as well as storage facilities.

Our reportable segments are Northeast G&P, Atlantic-Gulf, West, and NGL & Petchem Services.

- Northeast G&P is comprised of our midstream gathering and processing businesses in the Marcellus and Utica shale regions, as well as a 51 percent equity investment in Laurel Mountain and a 58 percent equity investment in Caiman II.
- Atlantic-Gulf is comprised of our interstate natural gas pipeline, Transco, and significant natural gas gathering and processing and crude oil production handling and transportation in the Gulf Coast region, as well as a 50 percent equity investment in Gulfstream, a 60 percent equity investment in Discovery, and a 41 percent interest in Constitution (a consolidated entity).
- West is comprised of our gathering, processing and treating operations in New Mexico, Colorado, and Wyoming and our interstate natural gas pipeline, Northwest Pipeline.
- NGL & Petchem Services is comprised of our 83.3 percent interest in an olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and various petrochemical and feedstock pipelines in the Gulf Coast region, an oil sands offgas processing plant near Fort McMurray, Alberta, and an NGL/olefin fractionation facility and B/B splitter facility at Redwater, Alberta. This segment also includes an NGL and natural gas marketing business, storage facilities and an undivided 50 percent interest in an NGL fractionator near Conway, Kansas, and a 50 percent equity investment in OPPL.

As of June 30, 2014, Williams holds an approximate 66 percent interest in us, comprised of an approximate 64 percent limited partner interest and all of our 2 percent general partner interest and IDRs.

Unless indicated otherwise, the following discussion and analysis of results of operations and financial condition and liquidity should be read in conjunction with the consolidated financial statements and notes thereto of this Form 10 Q and our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 19, 2014.

Management's Discussion and Analysis (Continued)

Proposed Merger

On July 1, 2014, Williams acquired all of the interests in Access Midstream Partners L.P. (ACMP) held by Global Infrastructure Partners II (GIP) which included 50 percent of the general partner interest and 55.1 million limited partner units for $5.995 billion in cash (ACMP Acquisition). Following the acquisition Williams owns 100 percent of the general partner interest, including incentive distribution rights, and approximately 50 percent of the limited partner units in ACMP. Williams has also proposed merging Williams Partners L.P. (WPZ) with and into ACMP in a unit-for-unit exchange at a ratio of 0.85 ACMP units per WPZ unit, subject to approval by each partnership's conflicts committees and board of directors and the WPZ unitholders. The proposal also includes an option for WPZ unitholders to take either a one-time special payment of $0.81 per unit, or an equivalent value of additional common units of ACMP, to compensate for lower expected per-unit limited partner cash distributions in 2015. All subsequent references to 2014 plan amounts within this Management's Discussion and Analysis do not reflect the proposed merger.

Distributions

In July 2014, our general partner's Board of Directors approved a quarterly distribution to unitholders of $0.9165 per common unit, an increase of approximately 1 percent over the prior quarter and 6 percent over the same period in the prior year. We expect to increase limited partner per-unit cash distributions by approximately 6 percent, at the midpoint of our guidance range, in 2014 and 2015.

Overview of Six Months Ended June 30, 2014

Our results for the first six months of 2014, as compared to the same period of the prior year, were unfavorable primarily due to lower NGL margins driven by lower volumes and lower olefin margins associated with the absence of volumes from our Geismar plant partially offset by related insurance recoveries. Interest expense related to higher debt levels also contributed to our lower results, partially offset by higher fee revenues. See additional discussion in Results of Operations.

Abundant and low-cost natural gas reserves in the United States continue to drive strong demand for midstream and pipeline infrastructure. We believe that we have successfully positioned our energy infrastructure businesses for significant future growth.

Canada Acquisition

On February 28, 2014, we acquired certain of Williams' Canadian operations for total consideration valued at approximately $1.2 billion. The operations included an oil sands offgas processing plant near Fort McMurray, Alberta, an NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta. We funded the transaction with $56 million of cash including $31 million that was paid in the second quarter, the issuance of 25,577,521 Class D limited-partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. In lieu of cash distributions, the Class D units receive quarterly distributions of additional paid-in-kind Class D units. All Class D units outstanding will be convertible to common units beginning in the first quarter of 2016. The contribution agreement governing the Canada Acquisition provides that we can issue additional Class D units to Williams on a quarterly basis through 2015 for up to a total of $200 million in cash for the purpose of funding certain facility expansions. At June 30, 2014, no additional Class D units have been issued to Williams under this provision. This common control acquisition was treated similar to a pooling of interests whereby the historical results of operations were combined with ours for all periods presented.

Geismar Incident

On June 13, 2013, an explosion and fire occurred at our Geismar olefins plant. The fire was extinguished on the day of the incident. The Geismar Incident rendered the facility temporarily inoperable and resulted in significant human, financial, and operational effects. This facility is part of our NGL & Petchem Services segment.

Management's Discussion and Analysis (Continued)

We have substantial insurance coverage for repair and replacement costs, lost production and additional expenses related to the incident as follows:

- Property damage and business interruption coverage with a combined per-occurrence limit of $500 million and retentions (deductibles) of $10 million per occurrence for property damage and a 60-day waiting period per occurrence for business interruption;
- General liability coverage with per-occurrence and aggregate annual limits of $610 million and retentions (deductibles) of $2 million per occurrence;
- Workers' compensation coverage with statutory limits and retentions (deductibles) of $1 million total per occurrence.

During the first six months of 2014, we received $175 million of insurance recoveries related to the Geismar Incident and incurred $14 million of related covered insurable expenses in excess of our retentions (deductibles). These amounts are reflected as a net gain in Net insurance recoveries- Geismar Incident within Costs and expenses in our Consolidated Statement of Comprehensive Income.

Following the repair and an expansion of the plant, we expect the Geismar plant to return to operation in the fourth quarter of 2014. The delay from the previous expectation resulted from the recent decision to install certain safety-related equipment and to provide additional contingency associated with the start-up process.

We expect our total loss to exceed our $500 million policy limit, which would result in a total claim of approximately $432 million related to business interruption and approximately $68 million related to the repair of the plant. Through June 2014, we have received a total of $225 million from insurers. We received $50 million of our most recent claim of $200 million as the insurers are evaluating our claim and have raised questions around key assumptions involving our business interruption claim. We continue to work with insurers in support of all claims, as submitted, and are vigorously pursuing collection of the remaining $275 million insurance limits. Further, we are impacted by certain uninsured losses, including amounts associated with the 60-day waiting period for business interruption, as well as other deductibles, policy limits, and uninsured expenses. Our assumptions and estimates, including the timing for the expanded plant return to operation, repair cost estimates, and insurance proceeds associated with our property damage and business interruption coverage, are subject to various risks and uncertainties that could cause the actual results to be materially different.

Northeast G&P

Caiman II

As a result of $119 million of contributions made in the first quarter of 2014, our ownership in the Caiman II joint project has increased to 58 percent at June 30, 2014. These contributions are used to fund Caiman II's 50 percent investment in Blue Racer Midstream LLC, which is expanding gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica Shale.

Atlantic-Gulf

New Transco rates effective

On August 31, 2012, Transco submitted to the FERC a general rate filing principally designed to recover increased costs and to comply with the terms of the settlement in its prior rate proceeding. The new rates became effective March 1, 2013, subject to refund and the outcome of a hearing. On August 27, 2013, Transco filed a stipulation and agreement with the FERC proposing to resolve all issues in this proceeding without the need for a hearing (Agreement). On December 6, 2013, the FERC issued an order approving the Agreement without modifications. Pursuant to its terms, the Agreement became effective March 1, 2014. We paid $118 million of rate refunds on April 18, 2014.

Management’s Discussion and Analysis (Continued)

Volatile Commodity Prices
NGL margins were approximately 23 percent lower in the first six months of 2014 compared to the same period of 2013 driven by lower volumes, as well as higher natural gas prices, partially offset by favorable non-ethane prices. Volumes declined primarily due to a customer contract in the West that expired in September 2013, as well as higher inventory levels. Due to unfavorable ethane economics, we further reduced our recoveries of ethane in our domestic plants in the first six months of 2014, compared to the same period in 2013. These reductions are substantially offset by new volumes generated by our Canadian ethane recovery facility which was placed into service in December 2013.

NGL margins are defined as NGL revenues less any applicable Btu replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both “keep-whole” processing agreements, where we have the obligation to replace the lost heating value with natural gas, and “percent-of-liquids” agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.
The following graph illustrates the effects of this price volatility, notably the decline in equity ethane sales driven by reduced recoveries, as well as the margin differential between ethane and non-ethane products and the relative mix of those products.

Management's Discussion and Analysis (Continued)

Company Outlook

Our strategy is to provide large-scale energy infrastructure designed to maximize the opportunities created by the vast supply of natural gas, natural gas products, and crude oil that exists in North America. We seek to accomplish this through further developing our scale positions in current key markets and basins and entering new growth markets and basins where we can become the large-scale service provider. We will maintain a strong commitment to safety, environmental stewardship, operational excellence and customer satisfaction. We believe that accomplishing these goals will position us to deliver an attractive return to our unitholders.

Fee-based businesses are a significant component of our portfolio. As we continue to transition to an overall business mix that is increasingly fee-based, the influence of commodity price fluctuations on our operating results and cash flows is expected to become somewhat less significant.

Our business plan for 2014 reflects both significant capital investment and continued growth in distributions. Our planned capital investments for 2014 total approximately $3.7 billion. We also expect approximately 6 percent growth in 2014 per common unit distributions. We expect to maintain an attractive cost of capital and reliable access to capital markets, both of which will allow us to pursue development projects and acquisitions.

Potential risks and obstacles that could impact the execution of our plan include:

- General economic, financial markets, or industry downturn;
- Unexpected significant increases in capital expenditures or delays in capital project execution;
- Lower than anticipated or delay in receiving insurance recoveries associated with the Geismar Incident;
- Limited availability of capital due to a change in our financial condition, interest rates, market or industry conditions;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- Decreased volumes from third parties served by our midstream business;
- Lower than anticipated energy commodity prices and margins;
- Changes in the political and regulatory environments;
- Physical damages to facilities, including damage to offshore facilities by named windstorms;
- Reduced availability of insurance coverage.

We continue to address these risks through maintaining a strong financial position and ample liquidity, as well as through managing a diversified portfolio of energy infrastructure assets.

In 2014, we anticipate an overall improvement in operating results compared to 2013 primarily due to an increase in our fee based and Canadian midstream businesses, partially offset by lower olefins and NGL margins and higher operating expenses associated with the growth of our business.

The following factors, among others, could impact our businesses in 2014.

Management’s Discussion and Analysis (Continued)

Commodity price changes

NGL and olefin price changes have historically correlated somewhat with changes in the price of crude oil, although NGL, olefin, crude, and natural gas prices are highly volatile and difficult to predict. Commodity margins are highly dependent upon regional supply/demand balances of natural gas as they relate to NGL margins, while olefins are impacted by continued supply and demand within the global economy. NGL prices will benefit from exports to satisfy global demand. NGL products are currently the preferred feedstock for ethylene and propylene production and are expected to remain advantaged over crude-based feedstocks into the foreseeable future. We continue to benefit from our strategic feedstock cost advantage in propylene production from Canadian oil sands offgas.

We anticipate the following trends in overall commodity prices in 2014 as compared to 2013:

- Natural gas prices are expected to be higher in part due to the additional demand to replace the gas volumes withdrawn during the colder than normal weather over the past winter season.
- Ethane prices are expected to be somewhat higher due to a modest increase in demand as well as slightly higher natural gas prices.
- Propane prices are expected to be higher from an increase in exports and higher natural gas prices.
- Propylene prices are expected to be comparable to 2013 prices.
- Ethylene prices and the overall ethylene crack spread are expected to be comparable to 2013 levels.

Gathering, transportation, processing, and NGL sales volumes

The growth of natural gas production supporting our gathering and processing volumes is impacted by producer drilling activities, which are influenced by commodity prices including natural gas, ethane and propane prices. In addition, the natural decline in production rates in producing areas impact the amount of gas available for gathering and processing. Due in part to the higher natural gas prices in the early part of 2014, we anticipate that overall drilling economics will improve slightly, which will benefit us in the long-term.

- In our Northeast G&P segment, we anticipate significant growth compared to the prior year in our natural gas gathering and processing volumes as our infrastructure grows to support drilling activities in the region.
- In our Atlantic-Gulf segment, we anticipate higher natural gas transportation revenues compared to 2013, as a result of expansion projects placed into service at Transco in 2013 and anticipated to be placed in service in 2014. We also expect higher production handling volumes compared to 2013, following the scheduled completion of Gulfstar FPS™ in third quarter 2014.
- Our West segment expects an unfavorable impact in equity NGL volumes in 2014 compared to 2013, primarily due to a customer contract that expired in September 2013.
- In 2014, we anticipate a continuation of periods when it will not be economical to recover ethane in our domestic businesses.
- Our NGL & Petchem Services segment anticipates new ethane volumes in 2014 associated with the December 2013 completion of the Canadian ethane recovery project, which is expected to benefit from a contractual minimum ethane sales price.

Olefin production volumes

- Our NGL & Petchem Services segment expects higher propylene volumes in 2014 than 2013. Volumes in 2013 were negatively impacted by both a planned maintenance turnaround and downtime associated with the tie-in of the Canadian ethane recovery project.

Management's Discussion and Analysis (Continued)

- Our NGL & Petchem Services segment anticipates lower ethylene volumes in 2014 compared to 2013, substantially due to the repair and expansion of the Geismar plant, which is expected to return to operation in the fourth quarter of 2014.

Other

- We anticipate higher operating expenses in 2014 compared to 2013, including depreciation expense related to our growing operations in our Northeast G&P segment and expansion projects in our Atlantic-Gulf segment.
- In our Atlantic-Gulf segment, we expect higher equity earnings compared to 2013 following the scheduled completion of Discovery's Keathley Canyon Connector™ lateral in the fourth quarter of 2014.

Expansion Projects

We expect to invest total capital in 2014 among our business segments as follows:

Segment:	Expansion Capital (Millions)
Northeast G&P	$1,400
Atlantic-Gulf	1,325
West	75
NGL & Petchem Services	590

Our ongoing major expansion projects include the following:

Northeast G&P

- Expansion of our gathering infrastructure including compression and gathering pipelines in the Susquehanna Supply Hub in northeastern Pennsylvania as production in the Marcellus increases. The Susquehanna Supply Hub is expected to reach a natural gas take away capacity of 3 Bcf/d by 2015.
- In the first half of 2014, we completed a 30 Mbbls/d expansion of the Moundsville fractionator facility, the construction of a 50-mile ethane pipeline, and the first phase of the condensate stabilization project in the Marcellus Shale. In third quarter 2014, we expect to complete the installation of 40 Mbbls/d of deethanization facilities, the first 200 MMcf/d of processing at Oak Grove, and the last phase of the condensate stabilization project.
- Construction of the Blue Racer Midstream joint project, an expansion to gathering and processing and the associated liquids infrastructure serving oil and gas producers in the Utica Shale, primarily in Ohio and Northwest Pennsylvania through capital to be invested within our Caiman II equity investment. Expansion plans included the addition of Natrium II, a second 200 MMcf/d processing plant, at Natrium, which was completed in April 2014. Construction of an additional 200 MMcf/d processing plant is underway at the Berne complex in Monroe County, Ohio. Berne I is expected to come online in the fourth quarter of 2014.

Atlantic-Gulf

- We designed, constructed, and are installing our Gulfstar FPS™, a spar-based floating production system that utilizes a standard design approach with a capacity of 60 Mbbls/d of oil, up to 200 MMcf/d of natural gas, and the capability to provide seawater injection services. Installation is under way and the project is expected to be in service in the third quarter of 2014. In December 2013, Gulfstar One agreed to host the Gunflint development, which will result in an expansion of the Gulfstar One system to provide production handling capacity of 20 Mbbls/d and 40 MMcf/d for Gunflint. The Gunflint project is expected to be completed in the first quarter of 2016, dependent on the producer's development activities.

Management's Discussion and Analysis (Continued)

- Discovery is constructing a 215-mile, 20-inch deepwater lateral pipeline in the central deepwater Gulf of Mexico that it will own and operate. Discovery has signed long-term agreements with anchor customers for natural gas gathering and processing services for production from the Keathley Canyon and Green Canyon areas. The Keathley Canyon Connector™ lateral will originate from a third-party floating production facility in the southeast portion of the Keathley Canyon area and will connect to Discovery's existing 30-inch offshore natural gas transmission system. The gas will be processed at Discovery's Larose Plant and the NGLs will be fractionated at Discovery's Paradis Fractionator. The lateral pipeline is estimated to have the capacity to flow more than 400 MMcf/d and will accommodate the tie-in of other deepwater prospects. The pipeline is expected to be in service in the fourth quarter of 2014.
- The Atlantic Sunrise Expansion Project involves an expansion of Transco's existing natural gas transmission system along with greenfield facilities to provide firm transportation from the northeastern Marcellus producing area to markets along Transco's mainline as far south as Station 85 in Alabama. We plan to file an application with the FERC in the second quarter of 2015 for approval of the project. We plan to place the project into service during the second half of 2017, assuming timely receipt of all necessary regulatory approvals, and it is expected to increase capacity by 1,700 Mdth/d.
- In September 2013, we filed an application with the FERC for Transco's Leidy Southeast Expansion project to expand our existing natural gas transmission system from the Marcellus Shale production region on Transco's Leidy Line in Pennsylvania to delivery points along its mainline as far south as Station 85 in Alabama. We plan to place the project into service during the fourth quarter of 2015, assuming timely receipt of all necessary regulatory approvals, and expect it to increase capacity by 525 Mdth/d.
- In April 2014, we received approval from the FERC to construct and operate an expansion of Transco's Mobile Bay line south from Station 85 in west central Alabama to delivery points along the line. We plan to place the project into service during the second quarter of 2015 and it is expected to increase capacity on the line by 225 Mdth/d.
- In June 2013, we filed an application with the FERC for authorization to construct and operate the jointly owned Constitution pipeline. We currently own 41 percent of Constitution with three other parties holding 25 percent, 24 percent, and 10 percent, respectively. We will be the operator of Constitution. The 126-mile Constitution pipeline will connect our gathering system in Susquehanna County, Pennsylvania, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in New York. We plan to place the project into service in late 2015 to 2016, assuming timely receipt of all necessary regulatory approvals, with an expected capacity of 650 Mdth/d. The pipeline is fully subscribed with two shippers.
- In May 2014, we received FERC approval for Transco's Northeast Connector project to expand our existing natural gas transmission system from southeastern Pennsylvania to the proposed Rockaway Delivery Lateral. We plan to place the project into service during the fourth quarter of 2014 and expect it to increase capacity by 100 Mdth/d.
- In May 2014, we received FERC approval for Transco's Rockaway Delivery Lateral project to construct a three-mile offshore lateral to a distribution system in New York. We plan to place the project into service during the fourth quarter of 2014, and the capacity of the lateral is expected to be 647 Mdth/d.
- In November 2013, we received approval from the FERC for Transco's Virginia Southside project to expand our existing natural gas transmission system from New Jersey to a proposed power station in Virginia and delivery points in North Carolina. We plan to place the project into service during the third quarter of 2015, and expect it to increase capacity by 270 Mdth/d.
- In June 2014, we filed an application with the FERC for Transco's Rock Springs Expansion project to expand our existing natural gas transmission system from New Jersey to a proposed generation facility in Maryland. The project is planned to be placed into service in third quarter 2016, assuming timely receipt of all necessary regulatory approvals, and is expected to increase capacity by 192 Mdth/d.

West

- Due to a reduction in drilling in the Piceance basin during 2012 and early 2013, we delayed the in-service date of our 350 MMcf/d cryogenic natural gas processing plant in Parachute that was planned for service in 2014. We are currently planning an in-service date in mid-2016. We will continue to monitor the situation to determine whether a different in-service date is warranted.

NGL & Petchem Services

- As a result of the Geismar Incident, the expansion of our Geismar olefins production facility is expected to be completed when the Geismar plant returns to operation. We expect the plant to return to operation in the fourth quarter of 2014. The expansion is expected to increase the facility’s ethylene production capacity by 600 million pounds per year to a new annual capacity of 1.95 billion pounds. The additional capacity will be wholly owned by us and is expected to increase our ownership of the Geismar production facility from the current 83.3 percent.
- In association with Williams’ long-term agreement to provide gas processing to a second bitumen upgrader in Canada’s oil sands near Fort McMurray, Alberta, we have a long-term agreement with Williams to provide fractionation service and plan to increase the capacity of the Redwater facilities where NGL/olefins mixtures will be fractionated into an ethane/ethylene mix, propane, polymer grade propylene, normal butane, an alkylation feed and condensate. This project is expected to be placed into service during the fourth quarter of 2015. We will receive a fee based payment from Williams for the fractionation service we provide to it.

Management's Discussion and Analysis (Continued)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2014, compared to the three and six months ended June 30, 2013. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended June 30,				Six months ended June 30,			
	2014	2013	$ Change*	% Change*	2014	2013	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues:								
Service revenues	$763	$717	+46	+6%	$1,526	$1,419	+107	+8%
Product sales	853	1,046	-193	-18%	1,783	2,150	-367	-17%
Total revenues	1,616	1,763			3,309	3,569		
Costs and expenses:								
Product costs	724	801	+77	+10%	1,493	1,591	+98	+6%
Operating and maintenance expenses	251	289	+38	+13%	499	546	+47	+9%
Depreciation and amortization expenses	207	191	-16	-8%	415	387	-28	-7%
Selling, general, and administrative expenses	132	131	-1	-1%	262	261	-1	-
Net insurance recoveries – Geismar Incident	(42)	—	+42	NM	(161)	—	+161	NM
Other (income) expense – net	27	4	-23	NM	44	5	-39	NM
Total costs and expenses	1,299	1,416			2,552	2,790		
Operating income	317	347			757	779		
Equity earnings (losses)	32	35	-3	-9%	55	53	+2	+4%
Interest expense	(117)	(96)	-21	-22%	(223)	(192)	-31	-16%
Other income (expense) – net	7	7	-	-	10	12	-2	-17%
Income before income taxes	239	293			599	652		
Provision for income taxes	5	21	+16	+76%	13	36	+23	+64%
Net income	234	272			586	616		
Less: Net income attributable to noncontrolling interests	2	1	-1	-100%	2	1	-1	-100%
Net income attributable to controlling interests	$232	$271			$584	$615		

* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to a change in signs, a zero-value denominator, or a percentage change greater than 200.

Three months ended June 30, 2014 vs. three months ended June 30, 2013

Service revenues increased primarily due to higher gathering volumes primarily in the Susquehanna Supply Hub, as well as an increase in natural gas transportation fee revenues related to new projects placed in service.

Product sales decreased primarily due to lower olefin sales volumes associated with the lack of production in 2014 as a result of the Geismar Incident. In addition, equity NGL sales decreased related to lower sales volumes, partially offset by higher per-unit sales prices, and crude oil marketing sales decreased related to natural declines in production areas served by our Mountaineer crude oil pipeline.

Management's Discussion and Analysis (Continued)

Product costs decreased primarily due to lower olefin feedstock purchases related to the lack of production as a result of the Geismar Incident and lower crude oil marketing purchases. The changes in marketing purchases are more than offset by similar changes in marketing revenues. In addition, natural gas purchases associated with the production of equity NGLs decreased reflecting lower volumes, partially offset by higher natural gas prices.
Operating and maintenance expenses decreased primarily due to a net increase in system gains and lower maintenance and repair expenses.
Depreciation and amortization expenses increased reflecting depreciation on new projects placed in service.
The favorable change in Net insurance recoveries – Geismar Incident is due to the receipt of $50 million of insurance recoveries partially offset by $8 million of related covered insurable expenses in excess of our retentions (deductibles) incurred in the second quarter of 2014. (See Note 4 – Other Income and Expenses of Notes to Consolidated Financial Statements.)
The unfavorable change in Other (income) expense – net within Operating income includes the following:

- $17 million of impairment charges recognized in 2014 related to certain equipment held for sale.
- The absence of $12 million of income from insurance recoveries in 2013 related to the abandonment of certain Eminence storage assets.
- The absence of $6 million of expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates.

Operating income decreased primarily due to a $90 million decrease in olefin margins, including $83 million lower product margins at our Geismar plant, and a $23 million decrease in NGL margins driven primarily by lower volumes, as well as $17 million of impairment charges recognized in 2014. These decreases are partially offset by $50 million of income associated with insurance recoveries in 2014 related to the Geismar Incident and a $46 million increase in service revenues.

Interest expense increased due to a $24 million increase in Interest incurred primarily due to new debt issuances in the fourth quarter of 2013 and first quarter of 2014. (See Note 7 – Debt and Banking Arrangements of Notes to Consolidated Financial Statements.)

Provision for income taxes changed favorably due to the absence of a $14 million charge associated with the impact of a Texas franchise tax law change in the second quarter 2013 and lower pre-tax income from international operations. See Note 5 – Provision for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.
Six months ended June 30, 2014 vs. six months ended June 30, 2013
Service revenues increased primarily due to higher gathering fees driven by higher volumes from new well connections and a net increase in gathering rates associated with customer contract modifications primarily in the Susquehanna Supply Hub. Additionally, natural gas transportation fee revenues increased primarily associated with expansion projects placed in service in 2013 and the implementation of new rates for Transco in March 2013. Partially offsetting these increases are lower production handling and crude oil transportation fee revenues in the eastern Gulf Coast primarily driven by lower Bass Lite production area volumes and producers' operational issues.
Product sales decreased primarily due to lower olefin sales volumes associated with the lack of production in 2014 as a result of the Geismar Incident and a decrease in volumes at our RGP splitter primarily due to an outage in a third-party storage facility. In addition, equity NGL sales decreased primarily reflecting lower non-ethane volumes, partially offset by higher average NGL per-unit sales prices and higher ethane volumes primarily in Canada.
Marketing revenues increased primarily due to higher NGL, natural gas, and crude oil prices and ethane volumes, partially offset by lower non-ethane, crude oil, and natural gas volumes.

Management's Discussion and Analysis (Continued)

Product costs decreased primarily due to lower olefin feedstock purchases related to the lack of production as a result of the Geismar Incident and a decrease in volumes at our RGP splitter as previously discussed. In addition, natural gas purchases associated with the production of equity NGLs decreased reflecting lower volumes, which were substantially offset by higher natural gas prices. These decreases were partially offset by an increase in marketing purchases. The changes in marketing purchases are more than offset by similar changes in marketing revenues.

Operating and maintenance expenses decreased primarily due to net favorable system gains and losses and lower maintenance and repair expenses.

Depreciation and amortization expenses increased reflecting depreciation on new projects placed in service.
The favorable change in Net insurance recoveries – Geismar Incident is due to the receipt of $175 million of insurance recoveries, partially offset by $14 million of related covered insurable expenses in excess of our retentions (deductibles) incurred in 2014. (See Note 4 – Other Income and Expenses of Notes to Consolidated Financial Statements.)
The unfavorable change in Other (income) expense – net within Operating income includes the following:

- $17 million of impairment charges recognized in 2014 related to certain equipment held for sale.
- The absence of $12 million of income from insurance recoveries in 2013 related to the abandonment of certain Eminence storage assets.
- A $10 million increase in amortization expense related to our regulatory asset associated with asset retirement obligations.
- The absence of $6 million of expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates.

Operating income decreased primarily due to a $212 million decrease in olefin margins, including $194 million lower product margins at our Geismar plant, a $61 million decrease in NGL margins driven primarily by lower volumes, as well as $17 million of impairment charges recognized in 2014. These decreases are partially offset by $175 million of income associated with insurance recoveries in 2014 related to the Geismar Incident and a $107 million increase in service revenues.

Interest expense increased due to a $37 million increase in Interest incurred primarily due to new debt issuances in the fourth quarter of 2013 and first quarter of 2014 (See Note 7 – Debt and Banking Arrangements of Notes to Consolidated Financial Statements.)

Provision for income taxes decreased primarily due to the absence of a $14 million charge associated with the impact of a Texas franchise tax law change in the second quarter 2013 and lower pre-tax income from international operations. See Note 5 – Provision for Income Taxes of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Management's Discussion and Analysis (Continued)

Period-Over-Period Operating Results – Segments
Northeast G&P

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Service revenues	$107	$78	$206	$141
Product sales	37	35	97	55
Segment revenues	144	113	303	196
Product costs	37	33	95	53
Depreciation and amortization expenses	40	32	79	61
Other segment costs and expenses	62	43	119	83
Equity (earnings) losses	(10)	(7)	(11)	(4)
Segment profit	$15	$12	$21	$3

Three months ended June 30, 2014 vs. three months ended June 30, 2013

Service revenues increased primarily due to $24 million higher gathering fees associated with 33 percent higher volumes driven by new well connections.

Depreciation and amortization expenses increased reflecting depreciation on new projects placed in service.

Other segment costs and expenses increased due primarily to $17 million of impairment charges related to certain equipment held for sale primarily at our Ohio Valley Midstream business and an increase in costs due to growth in operations.

Equity (earnings) losses changed favorably due to $8 million higher equity earnings from Caiman Energy II resulting primarily from business interruption insurance proceeds received in 2014. These earnings were offset by lower Laurel Mountain equity earnings of $5 million, due to the absence of an annual minimum volume commitment fee collected in 2013.

The favorable change in Segment profit is primarily due to an increase in fee revenues in the Susquehanna Supply Hub and higher equity earnings from Caiman Energy II, offset by $17 million of impairment charges, higher depreciation expense due to growth of the business, and lower equity earnings from Laurel Mountain.

Six months ended June 30, 2014 vs. six months ended June 30, 2013

Service revenues increased primarily due to $51 million higher gathering fees associated with 37 percent higher volumes driven by new well connections, a net increase in gathering rates associated with customer contract modifications primarily in the Susquehanna Supply Hub, and fewer maintenance issues in 2014. Service revenues also increased $8 million due to contributions from our Ohio Valley Midstream business resulting from the addition of processing and fractionation facilities placed in service in 2013 and 2014.

Product sales increased due primarily to growth in the NGL marketing activities attributable to the Ohio Valley Midstream business. The changes in marketing revenues are offset by similar changes in marketing purchases, reflected above as Product costs.

Depreciation and amortization expenses increased reflecting depreciation on new projects placed in service.

Other segment costs and expenses increased due primarily to $17 million of impairment charges related to certain equipment held for sale, $6 million of costs resulting from fire damages at a compressor station in the Susquehanna Supply Hub, and higher expenses associated with maintenance and growth in these operations.

Management's Discussion and Analysis (Continued)

Equity (earnings) losses changed favorably due primarily to $7 million higher equity earnings from Caiman Energy II resulting primarily from business interruption insurance proceeds received in 2014.

The favorable change in Segment profit is primarily due to an increase in service revenues and higher equity earnings from Caiman Energy II. These increases are partially offset by higher depreciation, $17 million of impairment charges related to certain equipment held for sale and higher expenses associated with growth in these operations.

Atlantic-Gulf

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Service revenues	$364	$353	$743	$711
Product sales	209	249	430	480
Segment revenues	573	602	1,173	1,191
Product costs	187	229	393	437
Depreciation and amortization expenses	91	87	185	180
Other segment costs and expenses	143	154	293	299
Equity (earnings) losses	(16)	(20)	(31)	(36)
Segment profit	$168	$152	$333	$311
NGL margin	$20	$19	$34	$41

Three months ended June 30, 2014 vs. three months ended June 30, 2013

Service revenues increased primarily due to a $14 million increase in Transco's natural gas transportation fee revenues primarily associated with expansion projects placed in service in 2013.

Product sales decreased primarily due to:

- A $24 million decrease in marketing revenues reflecting a decrease in crude oil marketing sales, partially offset by an increase in NGL marketing sales. Crude oil marketing sales decreased primarily due to lower crude oil volumes related to natural declines in production areas served by our Mountaineer crude oil pipeline, partially offset by higher crude oil prices. These changes in marketing revenues are offset by similar changes in marketing purchases.
- An $18 million decrease in system management gas sales from Transco. System management gas sales are offset in Product costs and, therefore, have no impact on Segment profit.

Product costs decreased primarily due to:

- A $24 million decrease in marketing purchases (offset in Product sales).
- $18 million lower system management gas costs (offset in Product sales).

Management's Discussion and Analysis (Continued)

Other segment costs and expenses decreased primarily due to the absence of Perdido pipeline relocation costs, the absence of expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset not recoverable in rates, higher reversals of project development costs from expense to capital associated with natural gas pipeline expansion projects, and the 2014 reversal of an over-accrual related to a litigation settlement. These decreases are partially offset by the absence of insurance recoveries recognized by Transco in 2013 related to the abandonment of certain of its Eminence storage assets.
Equity earnings from Discovery decreased reflecting the write-down of certain assets in second quarter 2014.
Segment profit increased primarily due to higher service revenues.

Six months ended June 30, 2014 vs. six months ended June 30, 2013
Service revenues increased primarily due to a $45 million increase in Transco's natural gas transportation fee revenues primarily associated with expansion projects placed in service in 2013 and the implementation of new rates for Transco in March 2013. These increases are partially offset by $10 million in lower production handling and crude oil transportation fee revenues in the eastern Gulf Coast primarily driven by lower Bass Lite production area volumes and producers' operational issues.
Product sales decreased primarily due to:

- A $29 million decrease in marketing revenues reflecting a decrease in crude oil marketing sales, partially offset by an increase in NGL marketing sales. Crude oil marketing sales decreased primarily due to lower crude oil volumes related to natural declines in production areas served by our Mountaineer crude oil pipeline, partially offset by higher crude oil prices. NGL marketing sales increased due to higher NGL prices, partially offset by lower volumes. These changes in marketing revenues are offset by similar changes in marketing purchases.
- A $15 million decrease in system management gas sales from Transco. System management gas sales are offset in Product costs and, therefore, have no impact on Segment profit.
- A $9 million decrease in revenues from our equity NGLs reflecting a $14 million decrease associated with lower equity NGL sales volumes, partially offset by a $5 million increase primarily associated with 13 percent higher average non-ethane per-unit sales prices. Equity NGL sales volumes are 30 percent lower driven by 26 percent lower non-ethane volumes as a result of customer contract changes, producers' operational issues, and natural declines in production area volumes.

Product costs decreased primarily due to:

- A $29 million decrease in marketing purchases (offset in Product sales).
- $15 million lower system management gas costs (offset in Product sales).

Other segment costs and expenses decreased primarily due to the absence of Perdido pipeline relocation costs, the absence of expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset not recoverable in rates, the net favorable impact of the 2014 reversal of an over-accrual related to a litigation settlement that was incurred in the first quarter of 2013, and higher reversals of project development costs from expense to capital associated with natural gas pipeline expansion projects. These decreases are partially offset by the absence of insurance recoveries recognized by Transco in 2013 related to the abandonment of certain of its Eminence storage assets, and higher amortization of a regulatory asset associated with asset retirement obligations.
Equity earnings from Discovery decreased reflecting the write-down of certain assets in second quarter 2014.
Segment profit increased primarily due to higher service revenues, partially offset by $7 million lower NGL margins reflecting lower volumes and higher NGL prices.

Management's Discussion and Analysis (Continued)

West

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Service revenues	$261	$260	$517	$518
Product sales	132	191	277	390
Segment revenues	393	451	794	908
Product costs	68	99	140	193
Depreciation and amortization expenses	60	58	118	119
Other segment costs and expenses	113	132	219	248
Segment profit	$152	$162	$317	$348
NGL margin	$60	$86	$125	$184

Three months ended June 30, 2014 vs. three months ended June 30, 2013

Service revenues increased slightly due primarily to minimum volume fees and favorable processing rates, largely offset by lower volumes associated with natural declines and certain contract changes.

Product sales decreased primarily due to:

- A $42 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $49 million due to lower volumes, partially offset by a $7 million increase primarily associated with 10 percent higher average non-ethane per-unit sales prices. Lower sales volumes are driven by a 33 percent decrease in non-ethane volumes primarily due to a customer contract that expired in September 2013 and higher inventory levels.
- An $18 million decrease in NGL marketing revenues primarily due to lower non-ethane volumes related to the expiration of a customer contract (more than offset in Product costs).

Product costs decreased primarily due to:

- A $19 million decrease in NGL marketing purchases (offset in Product sales).
- A $16 million decrease in natural gas purchases associated with the production of equity NGLs reflecting a $23 million decrease related to lower natural gas volumes, partially offset by a $7 million increase driven by higher average natural gas prices.

The decrease in Other segment costs and expenses is primarily due to a net increase in system gains and reduced gathering fuel expense.

Segment profit decreased primarily due to $26 million lower NGL margins reflecting lower NGL volumes and higher per-unit natural gas costs, partially offset by higher average non-ethane prices. This decrease was partially offset by a net increase in system gains as well as reduced gathering fuel expense.

Six Months Ended June 30, 2014 vs. six months ended June 30, 2013

Service revenues decreased slightly due primarily to lower volumes associated with natural declines and certain contract changes, largely offset by minimum volume fees and favorable processing rates.

Management's Discussion and Analysis (Continued)

Product sales decreased primarily due to:

- An $81 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $97 million due to lower volumes, partially offset by a $16 million increase primarily associated with 11 percent higher average non-ethane per-unit sales prices. Lower sales volumes are driven by a 33 percent decrease in non-ethane volumes primarily due to a customer contract that expired in September 2013 and higher inventory levels.
- A $34 million decrease in NGL marketing revenues primarily due to lower non-ethane volumes related to the expiration of a customer contract, slightly offset by higher non-ethane per-unit prices (offset in Product costs).

Product costs decreased primarily due to:

- A $35 million decrease in NGL marketing purchases (offset in Product sales).
- A $22 million decrease in natural gas purchases associated with the production of equity NGLs reflecting a $40 million decrease related to lower natural gas volumes, partially offset by a $18 million increase driven by higher average natural gas prices.

The decrease in Other segment costs and expenses is primarily due to net favorable system gains and losses, resulting from system gains in 2014 compared to system losses in 2013, and reduced gathering fuel expense.

Segment profit decreased primarily due to $59 million lower NGL margins reflecting lower NGL volumes and higher per-unit natural gas costs, partially offset by higher average non-ethane prices. This decrease was partially offset by net favorable system gains and losses as well as reduced gathering fuel expense.

NGL & Petchem Services

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
	(Millions)			
Service revenues	$32	$30	$62	$57
Product sales	751	863	1,526	1,794
Segment revenues	783	893	1,588	1,851
Product costs	711	735	1,415	1,485
Depreciation and amortization expenses	16	14	33	27
Other segment (income) costs and expenses	4	51	(72)	93
Equity (earnings) losses	(6)	(8)	(13)	(13)
Segment profit	$58	$101	$225	$259
Olefins margin	$27	$117	$55	$267
NGL margin	12	12	38	35
Marketing margin	(2)	(5)	13	1

Management's Discussion and Analysis (Continued)

Three months ended June 30, 2014 vs. three months ended June 30, 2013

Product sales decreased primarily due to:

- A $132 million decrease in olefin sales due to $140 million of lower sales volumes, partially offset by $8 million higher per-unit sales prices. Lower sales volumes are primarily due to a $129 million decrease in volumes at our Geismar facility due to the lack of production in 2014 as a result of the Geismar Incident and a $9 million decrease in Canadian olefin volumes driven by operational issues at the off-gas provider. These decreased volumes were partially offset by a $7 million increase in per-unit sales prices at our RGP splitter (substantially offset in Product costs).
- An $11 million increase in marketing revenues due primarily to higher ethane volumes and prices, as well as higher non-ethane and natural gas prices, partially offset by lower non-ethane and natural gas volumes.
- An $8 million increase in NGL sales revenues primarily due to new Canadian ethane volumes generated by the ethane recovery project placed in service in December 2013. Non-ethane per-unit sales prices were also higher, partially offset by lower non-ethane sales volumes driven by operational issues at the off-gas provider.

Product costs decreased primarily due to:

- A $42 million decrease in olefin feedstock purchases primarily due to a $45 million decrease in volumes at our Geismar facility due to the lack of production in 2014 as a result of the Geismar Incident, partially offset by a $6 million increase in per-unit costs at our RGP splitter (more than offset in Product sales). In Canada, lower volumes are offset by higher per-unit gas costs.
- A $8 million increase in marketing purchases primarily due to increased per-unit NGL costs (offset in Product sales).
- An $8 million increase in costs associated with our Canadian NGLs primarily due to new ethane volumes generated by the ethane recovery project and higher natural gas prices, partially offset by lower natural gas volumes associated with the production of non-ethane NGLs.

The favorable change in Other segment (income) costs and expenses is primarily due to the second-quarter 2014 receipt of $50 million of insurance recoveries, lower Canadian maintenance expenses, and the absence of the Geismar Incident insurance deductibles. These favorable changes are partially offset by $8 million of covered insurable expenses in excess of our retentions (deductibles) related to the Geismar Incident.

Segment profit decreased primarily due to $90 million lower Olefin product margins including $83 million lower product margins at our Geismar plant as a result of the Geismar Incident and $6 million lower Canadian olefin margins primarily due to lower volumes. Partially offsetting this decrease is a $47 million favorable change in Other segment (income) costs and expenses as previously discussed.

Six months ended June 30, 2014 vs. six months ended June 30, 2013

Product sales decreased primarily due to:

- A $322 million decrease in olefin sales due to $330 million of lower sales volumes, partially offset by $8 million higher per-unit sales prices. Lower sales volumes are primarily due to a $290 million decrease in volumes at our Geismar facility due to the lack of production in 2014 as a result of the Geismar Incident, a $26 million decrease in volumes at our RGP splitter primarily due to an outage in a third-party storage facility which caused us to reduce production (substantially offset in Product costs), and a $14 million decrease in Canadian olefin volumes due to limited production available for sale during the first quarter of 2014 as a result of downtime for the tie-in of the new ethane recovery system and to operational issues at the off-gas provider in the second quarter of 2014. These lower volumes are partially offset by $9 million higher per-unit sales prices at our RGP Splitter (substantially offset in Product costs).

Management’s Discussion and Analysis (Continued)

- A $31 million increase in marketing revenues due primarily to higher ethane volumes and prices, as well as higher non-ethane and natural gas prices, partially offset by lower non-ethane and natural gas volumes.
- A $25 million increase in NGL sales revenues primarily due to new Canadian ethane volumes generated by the ethane recovery project placed in service in December 2013. Non-ethane per-unit sales prices were also higher, partially offset by lower non-ethane sales volumes driven by limited production available for sale during the first quarter of 2014, as previously discussed, and operational issues at the off-gas provider.

Product costs decreased primarily due to:

- A $110 million decrease in olefin feedstock purchases primarily due to a $94 million decrease in volumes at our Geismar facility due to the lack of production in 2014 as a result of the Geismar Incident and a $23 million decrease in volumes at our RGP splitter primarily due to an outage in a third-party storage facility which caused us to reduce production (more than offset in Product sales). These lower volumes are partially offset by $7 million higher per-unit costs at our RGP Splitter (more than offset in Product sales).
- A $22 million increase in costs associated with our Canadian NGLs primarily due to new ethane volumes generated by the ethane recovery project and higher natural gas prices, partially offset by lower natural gas volumes associated with the production of non-ethane NGLs.
- A $19 million increase in marketing purchases primarily due to increased per-unit NGL costs.

The favorable change in Other segment (income) costs and expenses is primarily due to the 2014 receipt of $175 million of insurance recoveries, lower Canadian maintenance expenses, and the absence of the Geismar incident insurance deductibles. These favorable changes are partially offset by $14 million of covered insurable expenses in excess of our retentions (deductibles) related to the Geismar Incident.

Segment profit decreased primarily due to $212 million lower Olefin product margins including $194 million lower product margins at our Geismar plant as a result of the Geismar Incident and $16 million lower Canadian olefin margins due to lower volumes driven by limited production in the first quarter of 2014, as previously discussed, and operational issues at the off-gas provider. Partially offsetting this decrease is a $165 million favorable change in Other segment (income) costs and expenses as previously discussed and a $12 million increase in marketing margins primarily due to higher commodity prices.

Management's Discussion and Analysis (Continued)

Management's Discussion and Analysis of Financial Condition and Liquidity

Outlook

We seek to manage our businesses with a focus on applying conservative financial policy in order to maintain investment-grade credit metrics. Our plan for 2014 reflects our ongoing transition to an overall business mix that is increasingly fee-based. Although our cash flows are impacted by fluctuations in energy commodity prices, that impact is somewhat mitigated by certain of our cash flow streams that are not directly impacted by short-term commodity price movements, including:

- Firm demand and capacity reservation transportation revenues under long-term contracts;
- Fee-based revenues from certain gathering and processing services.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, unitholder distributions, and debt service payments while maintaining a sufficient level of liquidity. In particular, we note the following:

- We increased our per-unit quarterly distribution with respect to the second quarter of 2014 from \$0.9045 to \$0.9165. We expect to increase quarterly limited partner per-unit cash distributions by approximately 6 percent, at the midpoint of our guidance range, in 2014 and 2015.
- We expect to fund working capital requirements, capital and investment expenditures, debt service payments, and distributions to unitholders primarily through cash flow from operations, cash and cash equivalents on hand, issuances of debt and/or equity securities, and utilization of our commercial paper program and/or credit facility. In addition, we retain the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2014. Our internal and external sources of liquidity include:

- Cash and cash equivalents on hand;
- Cash generated from operations, including cash distributions from our equity-method investees and expected business interruption proceeds related to the Geismar Incident;
- Cash proceeds from issuances of debt and/or equity securities;
- Use of our commercial paper program and/or credit facility.

We anticipate our more significant uses of cash to be:

- Maintenance and expansion capital expenditures;
- Contributions to our equity-method investees to fund their expansion capital expenditures;
- Interest on our long-term debt;
- Quarterly distributions to our unitholders and general partner.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include those previously discussed in Company Outlook.

Management's Discussion and Analysis (Continued)

As of June 30, 2014, we had a working capital deficit (current liabilities in excess of current assets) of $547 million. However, we note the following about our available liquidity.

Available Liquidity	June 30, 2014 (Millions)
Cash and cash equivalents	$716
Capacity available under our $2.5 billion five-year credit facility (expires July 31, 2018), less amounts outstanding under the $2 billion commercial paper program (1)	2,500
	$3,216

(1) We have not borrowed on our credit facility during 2014. At June 30, 2014, we have no Commercial paper outstanding. The highest amount outstanding under the commercial paper program during 2014 was $900 million. At June 30, 2014, we are in compliance with the financial covenants associated with the credit facility and the commercial paper program. The full amount of the credit facility is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may, under certain conditions, be increased by up to an additional $500 million. Transco and Northwest Pipeline are each able to borrow up to $500 million under the credit facility to the extent not otherwise utilized by the other co-borrowers. In managing our available liquidity, we do not expect a maximum outstanding amount in excess of the capacity of our credit facility inclusive of any outstanding amounts under our commercial paper program.

In addition to the commercial paper program and credit facility listed above, we have issued letters of credit totaling $1 million as of June 30, 2014, under a bilateral bank agreement.

Debt Offerings

On June 27, 2014, we completed a public offering of $750 million of 3.9 percent senior unsecured notes due 2025 and $500 million of 4.9 percent senior unsecured notes due 2045. We used a portion of the net proceeds to repay amounts outstanding under our commercial paper program and expect to use the remainder to fund capital expenditures and for general partnership purposes.

On March 4, 2014, we completed a public offering of $1 billion of 4.3 percent senior unsecured notes due 2024 and $500 million of 5.4 percent senior unsecured notes due 2044. We used a portion of the net proceeds to repay amounts outstanding under our commercial paper program and the remainder to fund capital expenditures and for general partnership purposes.

Distributions from Equity-Method Investees

Our equity-method investees' organizational documents require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses.

Shelf Registration

In April 2013, we filed a shelf registration statement for the offer and sale from time to time of common units representing limited partner interests in us having an aggregate offering price of up to $600 million. These sales will be made over a period of time and from time to time in transactions at prices which are market prices prevailing at the time of sale, prices related to market price or at negotiated prices. Such sales will be made pursuant to an equity distribution agreement between us and certain banks who may act as sales agents or purchase for their own accounts as principals. As of June 30, 2014, no common units have been issued under this registration.

Management's Discussion and Analysis (Continued)

Insurance Renewal

Our onshore property damage and business interruption insurance coverage renewed on May 1st, with a combined per-occurrence limit of $750 million, subject to retentions (deductibles) of $40 million per occurrence for property damage and a waiting period of 120 days per occurrence for business interruption.

Credit Ratings

Our ability to borrow money is impacted by our credit ratings. The current ratings are as follows:

Rating Agency	Outlook	Senior Unsecured Debt Rating
Standard & Poor's	Stable	BBB
Moody's Investors Service	Stable	Baa2
Fitch Ratings	Stable	BBB

On June 16, 2014, all rating agencies affirmed these ratings which they consider investment grade.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of June 30, 2014, we estimate that a downgrade to a rating below investment grade could require us to post up to $316 million in additional collateral with third parties.

Capital and Investment Expenditures

Each of our businesses is capital-intensive, requiring investment to upgrade or enhance existing operations and comply with safety and environmental regulations. The capital requirements of these businesses consist primarily of:

- Maintenance capital expenditures, which are generally not discretionary, including: (1) capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives, (2) expenditures which are mandatory and/or essential to comply with laws and regulations and maintain the reliability of our operations, and (3) certain well connection expenditures.
- Expansion capital expenditures, which are generally more discretionary than maintenance capital expenditures, including: (1) expenditures to acquire additional assets to grow our business, to expand and upgrade plant or pipeline capacity and to construct new plants, pipelines and storage facilities, and (2) well connection expenditures which are not classified as maintenance expenditures.

The following table provides summary information related to our actual and expected capital expenditures, purchases of businesses, and contributions to equity-method investments for 2014. Included are gross increases to our property, plant, and equipment, including changes related to accounts payable and accrued liabilities:

	Maintenance		Expansion		Total	
Segment	2014 Estimate	Six months ended June 30, 2014	2014 Estimate	Six months ended June 30, 2014	2014 Estimate	Six months ended June 30, 2014
	(Millions)					
Northeast G&P	$20	$13	$1,400	$772	$1,420	$785
Atlantic-Gulf	175	44	1,325	637	1,500	681
West	125	30	75	19	200	49
NGL & Petchem Services	20	35	590	369	610	404
Other	—	4	—	—	—	4
Total	$340	$126	$3,390	$1,797	$3,730	$1,923

Management's Discussion and Analysis (Continued)

See Company Outlook - Expansion Projects for discussions describing the general nature of these expenditures.

Cash Distributions to Unitholders

We have paid quarterly distributions to unitholders and our general partner after every quarter since our initial public offering on August 23, 2005. We have increased our quarterly distribution from $0.9045 with respect to the first quarter of 2014 to $0.9165 per common unit, which will result in a distribution with respect to the second quarter of 2014 of approximately $577 million that will be paid on August 8, 2014, to the general and limited partners of record at the close of business on August 1, 2014. (See Note 3 – Allocation of Net Income and Distributions of Notes to Consolidated Financial Statements.)

Sources (Uses) of Cash

	Six months ended June 30, 2014	2013
	(Millions)	
Net cash provided (used) by:		
Operating activities	$914	$1,175
Financing activities	1,551	570
Investing activities	(1,859)	(1,654)
Increase (decrease) in cash and cash equivalents	$606	$91

Operating activities

The factors that determine operating activities are largely the same as those that affect Net income, with the exception of noncash expenses such as Depreciation and amortization. Our Net cash provided by operating activities was also impacted by net unfavorable changes in operating working capital.

Financing activities

Significant transactions include:

- $226 million net payments in 2014 and $710 million net borrowings in 2013 on commercial paper;
- $2.74 billion net received in 2014 from previously mentioned debt offerings;
- $1.705 billion received in 2013 from credit facility borrowings;
- $2.08 billion paid in 2013 on credit facility borrowings;
- $760 million received from our equity offerings in 2013, including $143 million received from Williams, which was used to repay credit facility borrowings;
- $1.122 billion, including $836 million to Williams, in 2014 and $915 million, including $700 million to Williams, in 2013 related to quarterly cash distributions paid to limited partner unitholders and the general partner;
- $116 million in 2014 and $251 million in 2013 received in contributions from noncontrolling interests in 2014.

Investing activities

Significant transactions include:

- Capital expenditures of $1.667 billion in 2014 and $1.494 billion in 2013;

- Purchases of and contributions to our equity method investments of $231 million in 2014 and $182 million in 2013.

Off-Balance Sheet Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Note 2 – Variable Interest Entities, Note 8 – Fair Value Measurements and Guarantee, and Note 9 – Contingent Liabilities of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Item 3
Quantitative and Qualitative Disclosures About Market Risk
Interest Rate Risk
Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first six months of 2014.
Foreign Currency Risk
Our foreign operations, whose functional currency is the local currency, are located primarily in Canada. Net assets of our foreign operations were approximately $1.1 billion and $1 billion at June 30, 2014 and December 31, 2013, respectively. These investments have the potential to impact our financial position due to fluctuations in these local currencies arising from the process of translating the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar would have changed total partners' equity by approximately $212 million at June 30, 2014.

Item 4
Controls and Procedures
Our management, including our general partner's Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a - 15(e) and 15d - 15(e) of the Securities Exchange Act) (Disclosure Controls) or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Williams Partners L.P. have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.
Evaluation of Disclosure Controls and Procedures
An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.
Changes in Internal Controls Over Financial Reporting
There have been no changes during the second quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.
PART II. OTHER INFORMATION

Item 1. Legal Proceedings
Environmental

Certain reportable legal proceedings involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment are described below. While it is not possible for us to predict the final outcome of the proceedings which are still pending, we do not anticipate a material effect on our consolidated financial position if we receive an unfavorable outcome in any one or more of such proceedings.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of Transco's compliance with the Clean Air Act. On March 28, 2008, the EPA issued notices of violation alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted a response denying the allegations in June 2008. In May 2011, Transco provided additional information to the EPA pertaining to these compressor stations in response to a request they had made in February 2011. In August 2010, the EPA requested, and Transco provided, similar information for a compressor station in Maryland. Since 2011, we have not received any additional requests for information related to these facilities.

In November 2013, we became aware of deficiencies with the air permit for the Ft. Beeler gas processing facility located in West Virginia. We notified the EPA and the West Virginia Department of Environmental Protection and are working to bring the Ft. Beeler facility into full compliance. At June 30, 2014, we have accrued liabilities of $100,000 for potential penalties arising out of the deficiencies.

Other

The additional information called for by this item is provided in Note 9 – Contingent Liabilities of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2013, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed, except as set forth below:

The time required to return our Geismar plant to operation following the explosion and fire at the facility on June 13, 2013, and the extent and timing of costs and insurance recoveries related to the incident could be materially different than we anticipate and could cause our financial results and levels of distributions to be materially different than we project.

Our projections of financial results and expected levels of distributions are based on numerous assumptions and estimates, including but not limited to the time required to return our Geismar plant to operation and complete the expansion project at the facility following the explosion and fire at the plant on June 13, 2013, and the extent and timing of costs and insurance recoveries related to the incident. Additionally, insurers continue to evaluate our claims and have recently raised questions around key assumptions involving our business interruption claim; as a result, the insurers have elected to make a partial payment pending further assessment of these issues. Although we currently expect to make full recovery of $500 million in insurance proceeds related to the Geismar incident, there can be no assurance that we will recover the full amount of our claims. Our total receipts from our insurers to date are $225 million. Our financial results and levels of distributions could be materially different than we project if our assumptions and estimates related to the incident are materially different than actual outcomes.

The Proposed Merger may not be approved by our Conflicts Committee and the ACMP Conflicts Committee or the terms on which such approval might be granted may differ from the initially proposed terms.

In connection with the announcement of the ACMP Acquisition, Williams proposed that, subsequent to the ACMP Acquisition, ACMP acquire us pursuant to the terms of the Proposed Merger. Prior to entering into a definitive agreement with respect to the Proposed Merger, each of our Conflicts Committee and the ACMP Conflicts Committee will be required to approve the Proposed Merger. In connection with obtaining such approval, the terms of the Proposed Merger, including the exchange ratio by which our common units would be converted into ACMP common units in connection with the Proposed Merger, will be subject to negotiation with each of our Conflicts Committee and the ACMP Conflicts Committee. Our Conflicts Committee and the ACMP Conflicts Committee may not approve the Proposed Merger, or if such approval is granted, the terms on which the Proposed Merger is approved may be significantly different than the initially proposed terms. Further, the market prices of our and ACMP’s common units could significantly fluctuate prior to the consummation of the Proposed Merger and any potential changes in the market prices of our or ACMP’s common units could affect whether our Conflicts Committee and the ACMP Conflicts Committee will approve the Proposed Merger, or if such approval is granted, the terms on which the Proposed Merger will be approved.

The successful execution of the integration strategy following the consummation of the Proposed Merger will involve considerable risks and may not be successful.

If the Proposed Merger is consummated, the success of the Proposed Merger will depend, in part, on the ability of the combined company to realize the anticipated benefits from combining ACMP's and our businesses. Realizing the benefits of the Proposed Merger will depend in part on the integration of assets, operations, functions and personnel while maintaining adequate focus on the core businesses of the combined company. Any expected cost savings, economies of scale, enhanced liquidity or other operational efficiencies, as well as revenue enhancement opportunities anticipated from the combination of ACMP and us, or other synergies, may not occur. The full benefit of the Proposed Merger is also based on an expected upgrade of ACMP's credit rating by independent credit rating agencies following the consummation of the Proposed Merger. This upgrade may not occur.

The combined company's management team will face challenges inherent in efficiently managing an increased number of employees over larger geographic distances, including the need to implement appropriate systems, policies, benefits and compliance programs. If management of the combined company is unable to minimize the potential disruption of the combined company's ongoing business and the distraction of management during the integration process, the anticipated benefits of the Proposed Merger may not be realized or may only be realized to a lesser extent than expected. In addition, the inability to successfully manage the implementation of appropriate systems, policies, benefits and compliance programs for the combined company or the geographically more diverse and substantially larger combined organization could have an adverse effect on the combined company after the Proposed Merger. These integration-related activities also could have an adverse effect on each of ACMP and us pending the completion of the Proposed Merger.

It is possible that the integration process could result in the loss of key employees, as well as the disruption of each of ACMP's and our ongoing businesses or the creation of inconsistencies between ACMP's and our standards, controls, procedures and policies. Any or all of those occurrences could adversely affect the combined company's ability to maintain relationships with service providers, customers and employees after the Proposed Merger or to achieve the anticipated benefits of the Proposed Merger.

The combined company's operating expenses may increase significantly over the near term due to the increased headcount, expanded operations and expenses or other changes related to the Proposed Merger. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the Proposed Merger and materially and adversely affect the combined company's business, operating results and financial condition.

Williams controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has limited duties, and it and its affiliates may have conflicts of interest with us and our unitholders, and our general partner and its affiliates may favor their interests to the detriment of our unitholders.

Williams owns and controls our general partner and appoints all of the directors of our general partner. Although our general partner has a contractual duty to manage us in a manner beneficial to us, the directors and officers of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to Williams. Therefore, conflicts of interest may arise between Williams and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following factors:

- Neither our partnership agreement nor any other agreement requires Williams or its affiliates to pursue a business strategy that favors us. Williams' directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Williams, which may be contrary to the best interests of us and our unitholders;
- All of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams and certain of its affiliates, and these persons will owe fiduciary duties to those entities;

- Our general partner is allowed to take into account the interests of parties other than us, such as Williams and its affiliates, in resolving conflicts of interest;
- As of June 30, 2014, Williams owns common and Class D units representing an approximate 64 percent limited partner interest in us. If a vote of limited partners is required in which Williams is entitled to vote, Williams will be able to vote its units in accordance with its own interests, which may be contrary to our interests or the interests of our unitholders;
- All of the executive officers and certain of the directors of our general partner will devote significant time to our business and/or the business of Williams, and will be compensated by Williams for the services rendered to them;
- Our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;
- Our general partner determines the amount and timing of any capital expenditures and, based on the applicable facts and circumstances and, in some instances, with the concurrence of the conflicts committee of its board of directors, whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure or investment capital expenditure, neither of which reduces operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner with respect to its incentive distribution rights;
- In some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions even if the purpose or effect of the borrowing is to make incentive distributions to itself as general partner;
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us, controls the enforcement of obligations owed to us by it and its affiliates and decides whether to retain separate counsel, accountants or others to perform services for us;
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- Our general partner has limited liability regarding our contractual and other obligations and in some circumstances is required to be indemnified by us;
- Pursuant to our partnership agreement, our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80 percent of our outstanding common units.

Affiliates of our general partner, including Williams, are not limited in their ability to compete with us and may exclude us from opportunities with which they are involved. In addition, all of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams, and these persons will owe fiduciary duties to Williams.

While our relationship with Williams and its affiliates is a significant attribute, it is also a source of potential conflicts. For example, Williams and its affiliates are in the natural gas business and are not restricted from competing with us. Williams and its affiliates may acquire, construct or dispose of natural gas industry assets in the future, some or all of which may compete with our assets, without any obligation to offer us the opportunity to purchase or construct such assets. In addition, all of the executive officers and certain of the directors of our general partner are also officers and/or directors of Williams and certain of its affiliates and will owe fiduciary duties to those entities.

Item 6. Exhibits

Exhibit No.		Description
Exhibit 3.1	—	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P.'s registration statement on Form S-1 (File No. 333-124517) and incorporated herein by reference).
Exhibit 3.2	—	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P.'s registration statement on Form S-1 (File No. 333-124517) and incorporated herein by reference).
Exhibit 3.3	—	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, and 11. (filed on May 1, 2014 as Exhibit 3.3 to Williams Partners L.P.'s Form 10-Q (File No. 001-32599) and incorporated herein by reference).
Exhibit 3.4	—	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
Exhibit 10.1	—	Sixth Supplemental Indenture, dated as of June 27, 2014, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A., as trustee. (filed on June 27, 2014 as Exhibit 4.1 to Williams partners L.P.'s current report on Form 8-K (File No. 001-32599) and incorporated herein by reference).
*Exhibit 12	—	Computation of Ratio of Earnings to Fixed Charges.
*Exhibit 31.1	—	Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*Exhibit 31.2	—	Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**Exhibit 32	—	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*Exhibit 101.INS	—	XBRL Instance Document.
*Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
*Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
*Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
*Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
*Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith
** Furnished herewith

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WILLIAMS PARTNERS L.P.
(Registrant)
By: Williams Partners GP LLC, its general partner

/s/ Ted T. Timmermans
Ted T. Timmermans
Vice President, Controller, and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)

July 31, 2014

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