Williams Partners L.P.
Form 10-Q
October 31, 2013

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 September 30, 2013
or

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

For the transition period from _____________ to _____________
Commission file number 1-32599

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 outstanding as of October 30, 2013.

Williams Partners L.P.
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Certain matters contained in this report 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.

All statements, other than statements of historical facts, included in this report 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," "assumes," "forecasts," "intends," "might," "goals," "c "planned," "potential," "projects," "scheduled," "will," "guidance," "outlook," "in service date" or other similar expressions. T statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- 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;
- The levels of cash distributions to unitholders;
- Seasonality of certain business components;
- Natural gas, natural gas liquids, and olefins prices, supply and demand; and
- Demand for our services.

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 report. Limited partner units are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the risk factors discussed below in addition to the other information in this report. If any of the following risks were actually to occur, our business, results of operations, and financial condition could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline, and unitholders could lose all or part of their investment. 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:

- 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, 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;
- Ability to acquire new businesses and assets and 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;
- 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 strategy and 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; and
- 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 report. 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, 2012, and Part II, Item 1A. Risk Factors of this Form 10-Q.

PART I – FINANCIAL INFORMATION

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions, except per-unit amounts)			
Revenues:				
Service revenues	$731	$668	$2,147	$2,005
Product sales	855	1,049	2,922	3,497
Total revenues	1,586	1,717	5,069	5,502
Costs and expenses:				
Product costs	718	781	2,326	2,662
Operating and maintenance expenses	245	252	770	736
Depreciation and amortization expenses	190	185	565	515
Selling, general, and administrative expenses	122	134	370	408
Other (income) expense – net	(26)	10	(19)	28
Total costs and expenses	1,249	1,362	4,012	4,349
Operating income	337	355	1,057	1,153
Equity earnings (losses)	31	30	84	87
Interest incurred	(111)	(109)	(337)	(329)
Interest capitalized	17	8	50	16
Interest income	—	1	1	2
Other income (expense) – net	6	5	3	12
Net income	280	290	858	941
Less: Net income attributable to noncontrolling interests	1	—	2	—
Net income attributable to controlling interests	$279	$290	$856	$941
Allocation of net income for calculation of earnings per common unit:				
Net income attributable to controlling interests	$279	$290	$856	$941
Allocation of net income to general partner	55	157	300	457
Allocation of net income to common units	$224	$133	$556	$484
Basic and diluted net income per common unit	$.52	$.38	$1.34	$1.47
Weighted average number of common units outstanding (thousands)	428,682	350,519	414,949	328,649
Cash distributions per common unit	$.8775	$.8075	$2.5875	$2.3775
Other comprehensive income (loss):				
Net unrealized gain (loss) from derivative instruments	$1	$(11)	$2	$34
Reclassifications into earnings of net derivative instruments (gain) loss	—	(14)	—	(20)
Other comprehensive income (loss)	1	(25)	2	14
Comprehensive income	281	265	860	955
Less: Comprehensive income attributable to noncontrolling interests	1	—	2	—
Comprehensive income attributable to controlling interests	$280	$265	$858	$955

See accompanying notes.

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

	September 30, 2013	December 31, 2012
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$64	$20
Trade accounts and notes receivable	472	562
Inventories	225	173
Regulatory assets	32	39
Other current assets	71	56
Total current assets	864	850
Investments	2,113	1,800
Property, plant, and equipment, at cost	23,021	21,062
Accumulated depreciation	(7,147)	(6,775)
Property, plant, and equipment – net	15,874	14,287
Goodwill	646	649
Other intangibles	1,657	1,702
Regulatory assets, deferred charges, and other	479	421
Total assets	$21,633	$19,709
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$887	$851
Affiliate	88	117
Accrued interest	108	110
Asset retirement obligations	56	68
Other accrued liabilities	309	203
Commercial paper	371	—
Total current liabilities	1,819	1,349
Long-term debt	8,063	8,437
Asset retirement obligations	504	508
Regulatory liabilities, deferred income, and other	559	518
Contingent liabilities (Note 9)		
Equity:		
Partners' equity:		
Common units (438,625,699 units outstanding at September 30, 2013 and 397,963,199 units outstanding at December 31, 2012)	11,823	10,372
General partner	(1,451)	(1,487)
Accumulated other comprehensive income (loss)	—	(2)
Total partners' equity	10,372	8,883
Noncontrolling interests in consolidated subsidiaries	316	14
Total equity	10,688	8,897
Total liabilities and equity	$21,633	$19,709

See accompanying notes.

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

	Williams Partners L.P.				
	Common Units	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
	(Millions)				
Balance – December 31, 2012	$10,372	$(1,487)	$(2)	$14	$8,897
Net income	503	353	—	2	858
Other comprehensive income (loss)	—	—	2	—	2
Cash distributions (Note 3)	(1,037)	(367)	—	—	(1,404)
Sales of common units	1,962	—	—	—	1,962
Contributions from general partner	—	75	—	—	75
Contributions from noncontrolling interests	—	—	—	300	300
Other	23	(25)	—	—	(2)
Balance – September 30, 2013	$11,823	$(1,451)	$—	$316	$10,688

See accompanying notes.

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

	Nine months ended September 30,	
	2013	2012
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$858	$941
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	565	515
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	97	31
Inventories	(50)	26
Other current assets and deferred charges	9	24
Accounts payable	(45)	(135)
Accrued liabilities	101	(5)
Affiliate accounts receivable and payable – net	(30)	18
Other, including changes in noncurrent assets and liabilities	86	61
Net cash provided by operating activities	1,591	1,476
FINANCING ACTIVITIES:		
Proceeds from (payments of) commercial paper – net	370	—
Proceeds from long-term debt	1,705	2,109
Payments of long-term debt	(2,080)	(1,285)
Proceeds from sales of common units	1,962	2,559
General partner contributions	50	88
Distributions to limited partners and general partner	(1,404)	(1,046)
Contributions from noncontrolling interests	300	4
Other – net	(6)	—
Net cash provided by financing activities	897	2,429
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(2,117)	(1,449)
Net proceeds from dispositions	1	22
Purchases of businesses	—	(2,049)
Purchase of business from affiliates	25	—
Purchases of and contributions to equity method investments	(344)	(282)
Other – net	(9)	58
Net cash used by investing activities	(2,444)	(3,700)
Increase (decrease) in cash and cash equivalents	44	205
Cash and cash equivalents at beginning of period	20	163
Cash and cash equivalents at end of period	$64	$368

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 13, 2013 (2012 Annual Financial Statements). 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 September 30, 2013, Williams owns an approximate 62 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).

Basis of Presentation

Organizational restructuring

Following Williams’ spin-off of WPX Energy, Inc. (WPX) at the end of 2011 and in consideration of the growth plans of the ongoing business, Williams initiated an organizational restructuring evaluation to better align resources to support an overall business strategy 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. As a result of this review, a new structure was implemented effective January 1, 2013, that generally organizes our businesses into geographically based operating areas. We have changed our segment reporting structure to align with the new operating areas resulting from the organizational restructuring, as this is consistent with the manner in which our Chief Operating Decision Maker evaluates performance and makes resource allocation decisions. Beginning in the first quarter of 2013, 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 Midstream, LLC (Laurel Mountain) and a 47.5 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. (Gulfstream), a 41 percent consolidated interest in Constitution Pipeline Company, LLC (Constitution), and a 60 percent equity investment in Discovery Producer Services LLC (Discovery).

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

Notes (Continued)

NGL & Petchem Services is comprised of our natural gas liquid (NGL) and natural gas marketing business, an NGL fractionator and storage facilities near Conway, Kansas, a 50 percent equity investment in Overland Pass Pipeline, LLC (OPPL), and an 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.

Other

As disclosed in our 2012 Annual Financial Statements, we acquired an entity in November 2012 that holds an 83.3 percent undivided interest in an olefins-production facility in Geismar, Louisiana, and associated assets from Williams. The acquired entity was an affiliate of Williams at the time of the acquisition; therefore, the acquisition was accounted for as a common control transaction, similar to a pooling of interests, whereby the assets and liabilities of the acquired entity were combined with ours at their historical amounts. As a result, prior period financial statement amounts and disclosures have been recast for this transaction. The effect of recasting our financial statements to account for this transaction increased net income $53 million and $163 million for the three and nine months ended September 30, 2012, respectively. This acquisition does not impact historical earnings per common unit as pre-acquisition earnings were allocated to our general partner. In first-quarter 2013, we received $25 million in cash from Williams and Williams waived $4 million in payments on its IDRs with respect to our May 2013 distribution related to a working capital adjustment associated with the acquisition.

Also as disclosed in our 2012 Annual Financial Statements, we have revised the overall presentation of our Consolidated Statement of Comprehensive Income, including the separate presentation of service revenues, product sales, product costs, and depreciation and amortization expenses. All prior periods presented have been recast, along with corresponding information presented in the Notes to Consolidated Financial Statements, to reflect this change.

Proposed acquisition

On October 30, 2013, we announced our intent to pursue an agreement to acquire certain of Williams' Canadian operations, including an oil sands offgas processing plant near Fort McMurray, an NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, and the Boreal pipeline. The transaction is subject to execution of an agreement, review and recommendation by the Conflicts Committee of our general partner, and approval of both our and Williams' Board of Directors.

Note 2 – Variable Interest Entities

Consolidated VIEs

We consolidate variable interest entities (VIEs) of which we are the primary beneficiary. The primary beneficiary of a VIE is the entity that has both (1) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (2) the obligation to absorb losses or the right to receive benefits that could be significant to the VIE. As of September 30, 2013, we consolidate the following VIEs:

Gulfstar

During the second quarter of 2013, a third party contributed $187 million to Gulfstar One LLC (Gulfstar) in exchange for a 49 percent ownership interest in Gulfstar. This contribution was based on 49 percent of our estimated cumulative net investment to date. The $187 million was then distributed to us. Following this transaction, we own a 51 percent interest in Gulfstar, 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's economic performance. We, as construction agent for Gulfstar, are designing, constructing, and 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 mid-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 $400 million, which will be funded with capital contributions from us and the

Notes (Continued)

other equity partner, proportional to ownership interest. 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.

Constitution

During the second quarter of 2013, a third party contributed $4 million to Constitution in exchange for a 10 percent ownership interest in Constitution. This contribution was based on 10 percent of Constitution's contributed capital to date. The $4 million was then distributed to us. Following this transaction, 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 March 2015 and estimate the total remaining construction costs of the project to be less than $625 million, which will be funded with capital contributions from us and the other equity partners, proportional to ownership interest.

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:

	September 30, 2013	December 31, 2012	Classification
	(Millions)		
Assets (liabilities):			
Cash and cash equivalents	$33	$8	Cash and cash equivalents
Construction in progress	850	556	Property, plant, and equipment, at cost
Accounts payable	(110)	(128)	Accounts payable - trade
Construction retainage	(2)	—	Other accrued liabilities
Deferred revenue associated with customer advance payments	(110)	(109)	Regulatory liabilities, deferred income, and other

Nonconsolidated VIEs

We have also identified certain interests in VIEs where 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 $492 million at September 30, 2013.

Caiman II

Our 47.5 percent-owned equity-method investment in Caiman II has been determined to be a VIE because it has insufficient equity to finance activities during the construction stage of the Blue Racer Midstream joint project, which is 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. We are not the primary beneficiary because we do not have the power to direct the activities of Caiman II that most significantly impact its economic performance. Our maximum exposure to loss is limited to the $380 million of total contributions that we have committed to make. At September 30, 2013, the carrying value of our investment in Caiman II was $257 million, which substantially reflects our contributions to date.

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 September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Allocation of net income to general partner:				
Net income	$280	$290	$858	$941
Net income applicable to pre-partnership operations allocated to general partner	—	(53)	—	(163)
Net income applicable to noncontrolling interests	(1)	—	(2)	—
Net costs charged directly to general partner	1	1	1	1
Income subject to 2% allocation of general partner interest	280	238	857	779
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	6	5	17	16
Incentive distributions paid to general partner (a)	121	92	337	256
Net costs charged directly to general partner	(1)	(1)	(1)	(1)
Pre-partnership net income allocated to general partner interest	—	53	—	163
Net income allocated to general partner	$126	$149	$353	$434
Net income	$280	$290	$858	$941
Net income allocated to general partner	126	149	353	434
Net income allocated to noncontrolling interests	1	—	2	—
Net income allocated to common limited partners	$153	$141	$503	$507

(a) 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 net income 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.

We paid or have authorized payment of the following partnership cash distributions during 2012 and 2013 (in millions, except for per unit amounts):

			General Partner		
Payment Date	Per Unit Distribution	Common Units	2%	Incentive Distribution Rights	Total Cash Distribution
2/10/2012	$0.7625	$227	$6	$78	$311
5/11/2012	0.7775	268	8	86	362
8/10/2012	0.7925	274	7	92	373
11/9/2012	0.8075	287	8	99	394
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 (a)	0.8775	385	11	46	442

(a) The Board of Directors of our general partner declared this $0.8775 per unit cash distribution on October 25, 2013, to be paid on November 12, 2013 to unitholders of record at the close of business on November 5, 2013.

The 2012 and 2013 cash distributions paid to our general partner in the table above have been reduced by $131 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 as our large platform of growth projects moves toward completion.

Notes (Continued)

Note 4 – Other Accruals

On June 13, 2013, an explosion and fire occurred at our Geismar olefins plant located south of Baton Rouge, Louisiana, in an industrial complex, that resulted in the tragic deaths of two affiliate employees and injuries of additional affiliate employees and contractors. 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.

We have expensed $4 million and $10 million during the three and nine months ended September 30, 2013, respectively, of costs under our insurance deductibles in operating and maintenance expenses in the Consolidated Statement of Comprehensive Income. Recoveries under our business interruption policy will be recognized upon resolution of any contingencies with the insurer associated with the claim. Through September 30, 2013, we have recognized $50 million of insurance recoveries related to this incident as a gain to other (income) expense – net within costs and expenses in our Consolidated Statement of Comprehensive Income.
Included in selling, general, and administrative expenses are charges of $6 million and $13 million during the three and nine months ended September 30, 2012, respectively, related to Williams' engagement of a consulting firm to assist in better aligning resources to support our business strategy following Williams' spin-off of WPX. During the second quarter of 2012, we incurred acquisition transaction costs of $16 million related to the acquisition of 100 percent of the ownership interests in Caiman Eastern Midstream, LLC. These costs are also included in selling, general, and administrative expenses.
Other (income) expense – net within costs and expenses, in addition to the insurance recoveries mentioned above, includes:

- Charges of $9 million and $15 million for the three and nine months ended September 30, 2013, respectively, related to the portion of the Eminence abandonment regulatory asset that will not be recovered through rates, pursuant to Transco's agreement in principle associated with its general rate case filing (see Note 9 – Contingent Liabilities.). We also recognized income of $3 million and $15 million for the three and nine months ended September 30, 2013, respectively, related to insurance recoveries associated with this event;
- Charges of $2 million during the nine months ended September 30, 2013 and $2 million and $17 million during the three and nine months ended September 30, 2012, respectively, related to project development costs associated with natural gas pipeline expansion projects;
- A $9 million accrued loss in the three and nine months ended September 30, 2013 for a contingent liability associated with a pending producer claim against us;
- Charges of $8 million and $15 million during the three and nine months ended September 30, 2013 and $2 million and $5 million during the three and nine months ended September 30, 2012 related to the amortization of regulatory assets associated with asset retirement obligations.

Notes (Continued)

Other income (expense) – net below operating income for the nine months ended September 30, 2013, includes a charge of $14 million associated with the impact of a second quarter Texas franchise tax law change.

Note 5 – Inventories

	September 30, 2013	December 31, 2012
	(Millions)	
Natural gas liquids, olefins, and natural gas in underground storage	$144	$96
Materials, supplies, and other	81	77
	$225	$173

Note 6 – Debt and Banking Arrangements

Credit Facility

On July 31, 2013, we amended our $2.4 billion credit facility to increase the aggregate commitments to $2.5 billion and extend the maturity date to July 31, 2018. Additionally, Transco and Northwest Pipeline are each able to borrow up to $500 million under the amended credit facility to the extent not otherwise utilized by the other co-borrowers. Our credit facility may also, under certain conditions, be increased up to an additional $500 million. As a result of the modifications, the previously deferred fees and costs related to these facilities are being amortized over the term of the new arrangements.

Letter of credit capacity under our $2.5 billion credit facility is $1.3 billion. At September 30, 2013, no letters of credit have been issued and no loans are outstanding under our credit facility.

Commercial Paper Program

In March 2013, we initiated a commercial paper program. The program allows a maximum outstanding amount at any time of $2 billion of unsecured commercial paper notes. The maturities of the commercial paper notes vary but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or, alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. Proceeds from these notes are used for general partnership purposes, including funding capital expenditures, working capital, and partnership distributions. At September 30, 2013, $371 million of commercial paper is outstanding at a weighted average interest rate of 0.41 percent.

Note 7 – Partners' Capital

In August 2013, we completed an equity issuance of 21,500,000 common units. Subsequently, the underwriters exercised their option to purchase 3,225,000 common units. The net proceeds of approximately $1.2 billion were used to repay amounts outstanding under our commercial paper program, to fund capital expenditures and for general partnership purposes.

In March 2013, we completed an equity issuance of 14,250,000 common units, including 3,000,000 common units sold to Williams in a private placement. Subsequently, the underwriters exercised their option to purchase 1,687,500 common units. The net proceeds of approximately $760 million were used to repay amounts outstanding under our credit facility.

Notes (Continued)

Note 8 – Fair Value Measurements

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 September 30, 2013:					
Measured on a recurring basis:					
ARO Trust investments	$31	$31	$31	$—	$—
Energy derivatives assets not designated as hedging instruments	6	6	—	1	5
Energy derivatives liabilities not designated as hedging instruments	(3)	(3)	—	(1)	(2)
Additional disclosures:					
Notes receivable and other	8	8	1	7	—
Long-term debt, including current portion	(8,063)	(8,531)	—	(8,531)	—
Assets (liabilities) at December 31, 2012:					
Measured on a recurring basis:					
ARO Trust investments	$18	$18	$18	$—	$—
Energy derivatives assets not designated as hedging instruments	5	5	—	—	5
Energy derivatives liabilities not designated as hedging instruments	(1)	(1)	—	—	(1)
Additional disclosures:					
Notes receivable and other	11	10	2	8	—
Long-term debt, including current portion	(8,437)	(9,624)	—	(9,624)	—

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 2008 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

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Notes (Continued)

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 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 nine months ended September 30, 2013 or 2012.

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, 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.

Guarantees

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 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 September 30, 2013, we have accrued liabilities totaling $18 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.

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

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Notes (Continued)

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 September 30, 2013, 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 September 30, 2013, we have accrued liabilities totaling $7 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 Occupational Safety and Health Administration, the Chemical Safety Board, and the EPA to conduct investigations to determine the cause of the incident. On June 28, 2013, the Louisiana Department of Environmental Quality 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. 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, 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 do not specify any amounts for claimed damages, we cannot reasonably estimate a range of potential loss related to these contingencies at this time.

Rate Matters

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 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 that would resolve all issues in this proceeding without the need for a hearing after reaching an agreement in principle with the participants. The stipulation and agreement is subject to review and approval by the FERC. We have provided a reserve for rate refunds which we believe is adequate for any refunds that may be required.

On August 31, 2006, Transco submitted to the FERC a general rate filing principally designed to recover increased costs. The rates became effective March 1, 2007, subject to refund and the outcome of a hearing. All issues in this proceeding except one have been resolved by settlement.

The one issue reserved for litigation or further settlement relates to Transco's proposal to change the design of the rates for service under one of its storage rate schedules, which was implemented subject to refund on March 1, 2007. A hearing on that issue was held before a FERC Administrative Law Judge (ALJ) in July 2008. In November 2008, the ALJ issued an initial decision in which he determined that Transco's proposed incremental rate design is unjust and unreasonable. On January 21, 2010, the FERC reversed the ALJ's initial decision, and approved our proposed incremental rate design. Certain parties sought rehearing of the FERC's order and, on April 2, 2012, the FERC denied the rehearing request. On June 1, 2012, one party filed an appeal in the U.S. Court of Appeals for the D.C. Circuit challenging the FERC's orders approving our rate design proposal.

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, and equity earnings (losses). 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 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 September 30, 2013						
Segment revenues:						
Service revenues						
External	$93	$345	$266	$27	$—	$731
Internal	—	1	—	—	(1)	—
Total service revenues	93	346	266	27	(1)	731
Product sales						
External	47	203	10	595	—	855
Internal	—	14	202	70	(286)	—
Total product sales	47	217	212	665	(286)	855
Total revenues	$140	$563	$478	$692	$(287)	$1,586
Segment profit (loss)	$(1)	$137	$207	$62		$405
Less equity earnings (losses)	2	17	—	12		31
Segment operating income (loss)	$(3)	$120	$207	$50		374
General corporate expenses						(37)
Operating income						$337
Three months ended September 30, 2012						
Segment revenues:						
Service revenues						
External	$47	$331	$263	$27	$—	$668
Internal	—	6	3	—	(9)	—
Total service revenues	47	337	266	27	(9)	668
Product sales						
External	—	141	13	895	—	1,049
Internal	—	100	237	73	(410)	—
Total product sales	—	241	250	968	(410)	1,049
Total revenues	$47	$578	$516	$995	$(419)	$1,717
Segment profit (loss)	$(4)	$124	$223	$86		$429
Less equity earnings (losses)	(3)	24	—	9		30
Segment operating income (loss)	$(1)	$100	$223	$77		399
General corporate expenses						(44)
Operating income						$355
Nine months ended September 30, 2013						
Segment revenues:						
Service revenues						
External	$234	$1,048	$784	$81	$—	$2,147
Internal	—	9	—	—	(9)	—
Total service revenues	234	1,057	784	81	(9)	2,147
Product sales						

External	102	628	47	2,145	—	2,922
Internal	—	69	555	231	(855)	—
Total product sales	102	697	602	2,376	(855)	2,922
Total revenues	$336	$1,754	$1,386	$2,457	$(864)	$5,069
Segment profit (loss)	$2	$448	$555	$259		$1,264
Less equity earnings (losses)	6	53	—	25		84
Segment operating income (loss)	$(4)	$395	$555	$234		1,180
General corporate expenses						(123)
Operating income						$1,057

Notes (Continued)

	Northeast G&P	Atlantic-Gulf	West	NGL & Petchem Services	Eliminations	Total
	(Millions)					
Nine months ended September 30, 2012						
Segment revenues:						
Service revenues						
External	$108	$1,023	$799	$75	$—	$2,005
Internal	—	7	4	—	(11)	—
Total service revenues	108	1,030	803	75	(11)	2,005
Product sales						
External	—	482	34	2,981	—	3,497
Internal	—	333	838	158	(1,329)	—
Total product sales	—	815	872	3,139	(1,329)	3,497
Total revenues	$108	$1,845	$1,675	$3,214	$(1,340)	$5,502
Segment profit (loss)	$(20)	$416	$773	$202		$1,371
Less equity earnings (losses)	(12)	68	—	31		87
Segment operating income (loss)	$(8)	$348	$773	$171		1,284
General corporate expenses						(131)
Operating income						$1,153

The following table reflects total assets by reportable segment.

	Total Assets	
	September 30, 2013	December 31, 2012
	(Millions)	
Northeast G&P	$5,942	$4,745
Atlantic-Gulf	9,507	8,734
West	4,669	4,688
NGL & Petchem Services	1,781	1,500
Other corporate assets	330	409
Eliminations (1)	(596)	(367)
Total	$21,633	$19,709

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

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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, natural gas liquids (NGLs), and olefins through our gas pipeline and midstream businesses.

Our 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 Federal Energy Regulatory Commission (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 little 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 business 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.

Following Williams' spin-off of WPX Energy, Inc. (WPX) at the end of 2011 and in consideration of the growth plans of the ongoing business, Williams initiated an organizational restructuring evaluation to better align resources to support an ongoing business strategy 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. As a result of this review, a new structure was implemented effective January 1, 2013, that generally organizes our businesses into geographically based operating areas. Beginning in the first quarter of 2013, we have changed our segment reporting structure to align with the new operating areas resulting from the organizational restructuring, as this is consistent with the manner in which our Chief Operating Decision Maker evaluates performance and makes resource allocation decisions. 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 Midstream, LLC (Laurel Mountain) and a 47.5 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. (Gulfstream), a 60 percent equity investment in Discovery Producer Services LLC (Discovery), and a 41 percent consolidated interest in Constitution Pipeline Company, LLC (Constitution).
- West is comprised of our gathering, processing and treating operations in New Mexico, Colorado, and Wyoming and our interstate natural gas pipeline, Northwest Pipeline LLC (Northwest Pipeline).
- NGL & Petchem Services is comprised of our NGL and natural gas marketing business, an NGL fractionator and storage facilities near Conway, Kansas, a 50 percent equity investment in Overland Pass Pipeline Company LLC (OPPL), and an interest in an olefins production facility in Geismar, Louisiana, along with a refinery grade propylene splitter and pipelines in the Gulf Coast region.

Management's Discussion and Analysis (Continued)

Williams currently holds an approximate 64 percent interest in us, comprised of an approximate 62 percent limited partner interest and all of our 2 percent general partner interest and incentive distribution rights.

The following discussion and analysis of our 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 in Exhibit 99.1 of our Current Report on Form 8-K dated May 13, 2013.

Proposed Dropdown

On October 30, 2013, we announced our intent to pursue an agreement to acquire certain of Williams' Canadian operations, including an oil sands offgas processing plant near Fort McMurray, an NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, and the Boreal pipeline. We expect to fund the transaction through the issuance of a new class of limited-partner units to Williams. These units will receive quarterly distributions of additional paid-in-kind units, all of which will be convertible to common units at a future date. The transaction is subject to execution of an agreement, review and recommendation by the Conflicts Committee of our general partner, and approval of both our and Williams' Board of Directors.

Distributions

In October 2013, our general partner's Board of Directors approved a quarterly distribution to unitholders of $0.8775 per unit, an increase of approximately 2 percent over the prior quarter and 9 percent over the same period in the prior year. We expect to increase total limited partner cash distributions by approximately 9 percent in 2013 and 6 percent in 2014 and 2015, which is within the previously disclosed range of 6 percent to 8 percent for 2014 and 2015.

Overview of Nine Months Ended September 30, 2013

Our results for the first nine months of 2013, as compared to the same period of the prior year, were unfavorable primarily due to lower NGL margins driven by reduced ethane recoveries and decreases in average NGL per-unit sales prices, along with higher operating costs associated with ongoing growth in our Northeast G&P operations. Partially offsetting these unfavorable changes was an increase in 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.

Geismar Incident

On June 13, 2013, an explosion and fire occurred at our Geismar olefins plant located south of Baton Rouge, Louisiana, in an industrial complex, which resulted in the tragic deaths of two affiliate employees and injuries of additional affiliate employees and contractors. 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. This facility is part of our NGL & Petchem Services segment.

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.

Management's Discussion and Analysis (Continued)

We have been focused on conducting the causal investigations with the Occupational Safety and Health Administration and the Chemical Safety Board. We have expensed $4 million and $10 million during the three and nine months ended September 30, 2013, respectively, of costs under our insurance deductibles in operating and maintenance expenses in the Consolidated Statement of Comprehensive Income. Recoveries under our business interruption policy will be recognized upon resolution of any contingencies with the insurer associated with the claim. Through September 30, 2013, we have recognized $50 million of insurance recoveries related to this incident as a gain to other (income) expense - net within costs and expenses in our Consolidated Statement of Comprehensive Income. Following the repair and plant expansion, the Geismar plant is expected to be in operation by April 2014. We expect our insurance coverage will significantly mitigate our financial loss. We currently estimate $343 million of total cash recoveries from insurers related to business interruption losses. Our current damage assessment and repair plan reaffirmed the previously estimated cost of $102 million to repair the plant. We will be impacted by certain uninsured losses, including amounts associated with the 60-day waiting period for business interruption, as well as other deductibles 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

Three Rivers Midstream

In April 2013, we announced an agreement to launch a new midstream joint project to provide gas gathering and gas processing services for production located in northwest Pennsylvania. The project will invest in both wet-gas handling infrastructure and dry-gas infrastructure serving the Marcellus and Utica Shale wells in the area. We will initially own substantially all of the new project, Three Rivers Midstream, and operate the assets. Our partner has the right to invest capital and increase its ownership to a maximum of 50 percent by July 2015. The current estimate of the total cost of the project is expected to be approximately $150 million. This does not include the cost of the gathering system, which will be determined in the future based upon the producers' needs. Subsequent capital investment is expected as the business and scale increases.

Three Rivers Midstream has signed a long-term, fee-based dedicated gathering and processing agreement for our partner's production in the area, including approximately 275,000 dedicated acres. Three Rivers Midstream plans to construct a 200 million cubic feet per day (MMcf/d) cryogenic gas processing plant and related facilities at a location to be determined. The initial plant is expected to be placed into service in mid-2015. The system is expected to be connected to two major proposed developments in Pennsylvania-our partner's proposed ethylene cracker (feasibility study is in progress) in Beaver County and Williams' joint project to develop the Bluegrass Pipeline system that would deliver Marcellus and Utica liquids to the Gulf Coast and export markets.

Marcellus Shale

In the second quarter of 2013, we completed an expansion to our natural gas gathering system, processing facilities, and fractionator in our Ohio Valley Midstream business of the Marcellus Shale including a third turbo-expander at our Fort Beeler facility, which added 200 MMcf/d of processing capacity. In the first half of 2014, we expect to add fractionation capacity at our Moundsville fractionators bringing the NGL handling capacity to approximately 43 thousand barrels per day (Mbbls/d), complete our first turbo-expander at our Oak Grove facility to add 200 MMcf/d of processing capacity, and finalize the construction of our first deethanizer with a capacity of 40 Mbbls/d and the associated 50-mile ethane line to Houston, Pennsylvania.

Atlantic-Gulf

Mid-South

The Mid-South expansion project involves an expansion of Transco's mainline from Station 85 in Choctaw County, Alabama to markets as far downstream as North Carolina. In August 2011, we received approval from the FERC for the project. We placed the first phase of the project into service in the third quarter of 2012, which increased capacity

by 95 thousand dekatherms per day (Mdth/d). The second phase was placed into service in the second quarter of 2013, which increased capacity by an additional 130 Mdth/d.

Gulfstar

Effective April 1, 2013, we sold a 49 percent interest in Gulfstar One LLC (Gulfstar) to a third party for $187 million, representing their proportionate share of estimated capital expenditures to date for the construction of Gulfstar FPS™, which is a proprietary floating production system and has been under construction since late 2011. It is supported by multiple agreements with two major producers to provide production handling, export pipeline, oil and gas gathering and gas processing services for the Tubular Bells field development located in the eastern deepwater Gulf of Mexico. The Gulfstar FPS™ will tie into our wholly owned oil and gas gathering and gas processing systems in the eastern Gulf of Mexico. Gulfstar FPS™ is expected to have an initial capacity of 60 Mbbls/d, up to 200 MMcf/d of natural gas and the capability to provide seawater injection services. We expect Gulfstar FPS™ to be capable of serving as a central host facility for other deepwater prospects in the area. The project is expected to be in service in mid-2014.

Mid-Atlantic Connector

The Mid-Atlantic Connector Project involves an expansion of Transco's mainline from an existing interconnection with East Tennessee Natural Gas in North Carolina to markets as far downstream as Maryland. In July 2011, we received approval from the FERC for the project. We placed the project into service in the first quarter of 2013, and it increased capacity by 142 Mdth/d.

NGL & Petchem Services

Overland Pass Pipeline

Through our equity investment in OPPL, we completed the construction of a pipeline expansion in the second quarter of 2013, which increased the pipeline's capacity to 255 Mbbls/d. In addition, a new connection was completed in April 2013 to bring new volumes to OPPL from the Bakken Shale in the Williston basin.

Volume Impacts in 2013

Due to unfavorable ethane economics, we reduced our recoveries of ethane in our plants during most of the first nine months of 2013, which resulted in 29 percent lower NGL production volumes and 46 percent lower NGL equity sales volumes in the first nine months of 2013 compared to the same period of 2012.

As a result of the Geismar Incident, ethylene sales volumes have decreased 96 percent and 41 percent for the three and nine months ended 2013, respectively, compared to the same period of 2012.

Volatile Commodity Prices

NGL margins were approximately 42 percent lower in the first nine months of 2013 compared to the same period of 2012 driven by reduced ethane recoveries, as previously mentioned, coupled with lower NGL prices and higher natural gas prices. However, our average per-unit composite NGL margin in the first nine months of 2013 has increased slightly compared to the same period of 2012 as the relative mix of NGL products produced has shifted to a greater proportion of higher-margin non-ethane products.

NGL margins are defined as NGL revenues less any applicable British thermal unit (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.

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 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.

As previously noted, we expect the financial impact of the Geismar Incident will be significantly mitigated by our insurance policies. However, the timing of recognizing recoveries under our business interruption policy, as well as the effect of the 60-day waiting period, will likely cause a significant negative impact to our 2013 results.

In light of all of the above, our business plan for 2013 continues to reflect both significant capital investment and growth in distributions. Our planned capital investments for 2013 total approximately $3.6 billion which we expect to fund a significant portion through debt and equity issuances. We also expect approximately 9 percent growth in total 2013 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;

Management's Discussion and Analysis (Continued)

- Availability of capital;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- Decreased volumes from third parties served by our midstream business;
- Unexpected significant increases in capital expenditures or delays in capital project execution;
- Lower than anticipated energy commodity prices and margins;
- Changes in the political and regulatory environments;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms.

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

The following factors, among others, could impact our businesses in 2013.

Commodity price changes

We expect ethane prices to remain at current levels, which will result in continued ethane rejection across most of our systems. We further expect that the combination of lower NGL prices and higher natural gas prices will result in overall total NGL margins being lower than the previous year. NGL price changes have historically correlated somewhat with changes in the price of crude oil, although NGL, crude, and natural gas prices are highly volatile and difficult to predict. NGL margins are highly dependent upon regional supply/demand balances of natural gas. 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.

Gathering, 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 rates in producing areas impact the amount of gas available for gathering and processing.
- We anticipate significant growth compared to the prior year in our natural gas gathering volumes in our Northeast G&P segment as our infrastructure grows to support drilling activities in the region. Based on less favorable producer economics in the West segment, we expect a decrease in production and thus a lower supply of natural gas available to gather and process in 2013.
- We anticipate equity NGL volumes in 2013 to be lower than 2012 primarily due to periods when we expect it will not be economical to recover ethane. In addition, our equity NGL volumes were also impacted by a change in a customer's contract in the West segment from percent-of-liquids to fee-based processing, with a portion of the fee representing a share of the associated NGL margins.
- In our Atlantic-Gulf segment, we expect lower production handling and crude transportation volumes compared to 2012, as production flowing through our Devils Tower facility declines.
- We anticipate higher general and administrative, operating, and depreciation expense related to our growing operations in our Northeast G&P segment.

Management's Discussion and Analysis (Continued)

Eminence Storage Field Leak

On December 28, 2010, we detected a leak in one of the seven underground natural gas storage caverns at our Eminence Storage Field in Mississippi. Due to the leak and related damage to the well at an adjacent cavern, both caverns are out of service. In addition, two other caverns at the field, which were constructed at or about the same time as those caverns, have experienced operating problems, and we have determined that they should also be retired. The event has not affected the performance of our obligations under our service agreements with our customers.

In September 2011, we filed an application with the FERC seeking authorization to abandon these four caverns. In February 2013, the FERC issued an order approving the abandonment. We estimate the total abandonment costs, which will be capital in nature, will be approximately $103 million, which is expected to be spent through the first half of 2014. As of September 30, 2013, we have incurred approximately $92 million of these abandonment costs. This estimate is subject to change as work progresses and additional information becomes known. Management considers these costs to be prudent costs incurred in the abandonment of these caverns. Consistent with the terms of the pending rate case, for the three and nine months ended September 30, 2013, we expensed $9 million and $15 million, respectively, related to the Eminence abandonment regulatory asset that will not be recovered in rates. We have also recognized income for the three and nine months ended September 30, 2013, of $3 million and $15 million, respectively, related to insurance recoveries associated with this event.

Filing of rate cases

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 the hearing. On August 27, 2013, after reaching an agreement in principle with the participants, Transco filed with the FERC a stipulation and agreement that would resolve all issues in this proceeding without the need for a hearing. The stipulation and agreement is subject to review and approval by the FERC. We have provided a reserve for rate refunds which we believe is adequate for any refunds that may be required.

During the first quarter of 2012, Northwest Pipeline LLC (Northwest Pipeline) filed a Stipulation and Settlement Agreement with the FERC for an increase in their rates. Northwest Pipeline received FERC approval during the second quarter of 2012. The new rates, which as filed are 7.4 percent higher than the formerly applicable rates, became effective January 1, 2013.

Expansion Projects

We expect to invest total capital in 2013 among our business segments as follows:

Segment:	Expansion Capital (Millions)
Northeast G&P	$1,625
Atlantic-Gulf	1,150
West	145
NGL & Petchem Services	380

Management’s Discussion and Analysis (Continued)

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 billion cubic feet per day (Bcf/d) by 2015, including capacity contributions from the Constitution Pipeline.
- As previously discussed, we completed construction at our Fort Beeler facility in the Marcellus Shale, which added 200 MMcf/d of processing capacity in the second quarter of 2013. We have several significant projects under construction with targeted construction completion in the first half of 2014. We are completing a 43 Mbbls/d expansion of the Moundsville fractionator, installation of 40 Mbbls/d of deethanization capacity, a 50-mile ethane pipeline, condensate stabilization, and the first 200 MMcf/d of processing at Oak Grove. These projects are expected to provide the base facilities required to meet current contractual obligations.
- Expansions to Laurel Mountain’s gathering system infrastructure to increase the capacity to 700 MMcf/d by the end of 2015 through capital to be invested within this equity investment, also in the Marcellus Shale region.
- 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.

Atlantic-Gulf

- We will design, construct, and install 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, as previously discussed. Construction is under way and the project is expected to be in service in mid-2014.
- Our equity investee which we operate, Discovery, plans to construct, own, and operate a new 215-mile, 20-inch deepwater lateral pipeline in the central deepwater Gulf of Mexico. 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.
- In September 2013, we filed an application with the FERC for Transco’s Leidy Line 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 main system from Station 85 in Alabama. We plan to place the project into service in December 2015, and expect to increase capacity by an additional 525 Mdth/d.
- In July 2013, we filed an application with the FERC for 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 in April 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 new jointly-owned Constitution Pipeline. As of May 2013, we currently own 41 percent of Constitution Pipeline with three other parties holding 25 percent, 24 percent, and 10 percent, respectively. We will be the operator of Constitution Pipeline. The new 120-mile Constitution Pipeline will connect our gathering system in

Management's Discussion and Analysis (Continued)

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 March 2015, with an expected capacity of 650 Mdth/d. The pipeline is fully subscribed with two shippers.

- In April 2013, we filed an application with the FERC 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 second half of 2014, and expect to increase capacity by 100 Mdth/d.
- In January 2013, we filed an application with the FERC 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 second half of 2014, with an expected capacity of 647 Mdth/d.
- In December 2012, we filed an application with 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 a delivery point in North Carolina. We plan to place the project into service in September 2015, and expect to increase capacity by 270 Mdth/d.
- In November 2012, we received approval from the FERC for Transco's Northeast Supply Link project to expand our existing natural gas transmission system from the Marcellus Shale production region on the Leidy Line to various delivery points in New York and New Jersey. We plan to place the project into service in November 2013, and expect to increase capacity by an additional 250 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 an earlier 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, which is expected to occur in April 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 share of the Geismar production facility from the current 83.3 percent.

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 nine months ended September 30, 2013, compared to the three and nine months ended September 30, 2012. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended September 30,				Nine months ended September 30,			
	2013	2012	$ Change*	% Change*	2013	2012	$ Change*	% Change*
	(Millions)				(Millions)			
Revenues:								
Service revenues	$731	$668	+63	+9%	$2,147	$2,005	+142	+7%
Product sales	855	1,049	-194	-18%	2,922	3,497	-575	-16%
Total revenues	1,586	1,717	-131	-8%	5,069	5,502	-433	-8%
Costs and expenses:								
Product costs	718	781	+63	+8%	2,326	2,662	+336	+13%
Operating and maintenance expenses	245	252	+7	+3%	770	736	-34	-5%
Depreciation and amortization expenses	190	185	-5	-3%	565	515	-50	-10%
Selling, general, and administrative expenses	122	134	+12	+9%	370	408	+38	+9%
Other (income) expense – net	(26)	10	+36	NM	(19)	28	+47	NM
Total costs and expenses	1,249	1,362	+113	+8%	4,012	4,349	+337	+8%
Operating income	337	355			1,057	1,153		
Equity earnings (losses)	31	30	+1	+3%	84	87	-3	-3%
Interest expense	(94)	(101)	+7	+7%	(287)	(313)	+26	+8%
Interest income	—	1	-1	-100%	1	2	-1	-50%
Other income (expense) – net	6	5	+1	+20%	3	12	-9	-75%
Net income	280	290			858	941		
Less: Net income attributable to noncontrolling interests	1	—	-1	NM	2	—	-2	NM
Net income attributable to controlling interests	$279	$290			$856	$941		

* + = 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 September 30, 2013 vs. three months ended September 30, 2012

The increase in service revenues is primarily due to higher fee revenues associated with the growth in the businesses acquired in the 2012 acquisitions of Caiman Eastern Midstream, LLC (Caiman Acquisition) and certain entities from Delphi Midstream Partners, LLC (Laser Acquisition). This growth includes higher gathering volumes from new well connections resulting from infrastructure additions, increased gathering rates associated with customer contract modifications, and contributions from the processing and fractionation facilities placed in service in the latter half of

2012 and in 2013. Additionally, natural gas transportation fee revenues increased from expansion projects placed into service in 2012 and 2013 and the new rates effective during first-quarter 2013. These increases are partially offset by lower fee revenues in the eastern Gulf Coast primarily driven by natural declines in Bass Lite and Blind Faith production area volumes, as well as decreased gathering and processing fee revenues driven by lower volumes in the Piceance and Four Corners areas.

Management's Discussion and Analysis (Continued)

The decrease in product sales is primarily due to lower marketing revenues as a result of lower NGL prices and lower crude oil and natural gas volumes, partially offset by higher crude oil prices and higher natural gas prices. In addition, olefin production revenues decreased resulting from the loss of production as a result of the Geismar Incident. NGL production revenues also decreased due to lower volumes primarily driven by reduced ethane recoveries and a change in a certain customer contract from percent-of-liquids to fee-based processing, as well as decreases in average ethane per-unit sales prices.

The decrease in product costs is primarily due to decreased marketing purchases as a result of lower NGL prices and lower crude oil and natural gas volumes, partially offset by higher crude oil prices and higher natural gas prices. In addition olefin feedstock purchases decreased as a result of the Geismar Incident.

The decrease in operating and maintenance expenses is primarily due to lower compressor and pipeline maintenance and repair expenses resulting from the absence of expenses related to the substantial completion of our natural gas pipeline integrity management plan during 2012, and lower operating costs in our Four Corners area related to the consolidation of certain operations. These decreased expenses are partially offset by higher expenses associated with the subsequent growth in the operations of the businesses acquired in the Caiman and Laser Acquisitions, including higher pipeline maintenance and repair costs, and $4 million of costs incurred under our insurance deductibles resulting from the Geismar Incident.

The increase in depreciation and amortization expenses reflects increased depreciation expense in 2013 at Northeast G&P associated with the businesses acquired in 2012 and depreciation on subsequent infrastructure additions, partially offset by the absence of increased depreciation in 2012 on certain assets in the Gulf Coast region resulting from a change in the estimated useful lives.

The decrease in selling, general, and administrative expenses (SG&A) is primarily due to a reduction in allocated administrative expenses from Williams reflecting the absence of reorganization related costs in 2012 (see Note 4 – Other Accruals of Notes to Consolidated Financial Statements).

The favorable changes in other (income) expense – net within operating income primarily include $50 million of income associated with insurance recoveries related to the Geismar Incident and $3 million of insurance recoveries related to the abandonment of certain Eminence storage assets. Partially offsetting this income is a $9 million expense recognized in third-quarter 2013 related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates, and a $9 million accrued loss for a contingent liability associated with a pending producer claim against us.

The decrease in operating income generally reflects lower olefin production margins, lower NGL production margins and a decrease in marketing margins, partially offset by increased fee revenues and the favorable changes in other (income) expense – net as described above.

Interest expense decreased due to an increase in interest capitalized related to construction projects primarily at Northeast G&P and Atlantic-Gulf, partially offset by an increase in interest incurred primarily due to an increase in borrowings.

Nine months ended September 30, 2013 vs. nine months ended September 30, 2012

The increase in service revenues is primarily due to higher fee revenues associated with the growth in the businesses acquired in 2012, including higher volumes from new well connections resulting from infrastructure additions, a full nine month of operations from these businesses, increased gathering rates associated with customer contract modifications, as well as contributions from the processing and fractionation facilities placed in service in the latter half of 2012 and in 2013. Additionally, natural gas transportation fee revenues increased from expansion projects placed into service in 2012 and 2013 and new rates effective during first-quarter 2013. Partially offsetting these increases are decreased gathering and processing fee revenues, primarily due to a natural decline in production volumes, primarily in the Piceance basin, and severe winter weather conditions in the first quarter of 2013 which prevented producers from delivering gas. In addition, fee revenues decreased in the eastern Gulf Coast primarily driven by natural declines in Bass Lite and Blind Faith production area volumes.

Management's Discussion and Analysis (Continued)

The decrease in product sales is primarily due to a decrease in marketing revenues resulting from lower NGL prices, partially offset by higher natural gas volumes and prices. NGL production revenues also decreased due to lower volumes primarily driven by reduced ethane recoveries and decreases in average NGL per-unit sales prices. Also impacting the decrease are lower crude oil volumes related to natural declines in Bass Lite and Blind Faith production area and lower olefin production revenues primarily due to lower volumes from the loss of production as a result of the Geismar Incident, partially offset by higher per-unit sales prices.

The decrease in product costs is primarily due to lower marketing purchases resulting from lower NGL prices and lower crude oil volumes, partially offset by higher natural gas volumes and prices. In addition, olefin feedstock purchases decreased reflecting lower sales volumes and lower average per-unit feedstock costs. Costs associated with the production of NGLs also decreased primarily resulting from lower volumes, driven by lower ethane recoveries, partially offset by an increase in average natural gas prices.

The increase in operating and maintenance expenses is primarily associated with the subsequent growth in the operations of the businesses acquired in the Caiman and Laser Acquisitions, including increased pipeline maintenance and repair costs and $10 million of costs incurred under our insurance deductibles resulting from the Geismar Incident. These increases are partially offset by lower compressor and pipeline maintenance and repair expenses, primarily due to the absence of expenses related to the substantial completion of our natural gas pipeline integrity management plan during 2012, and lower operating costs in our Four Corners area related to the consolidation of certain operations.

The increase in depreciation and amortization expenses reflects a full nine months of depreciation expense in 2013 at Northeast G&P associated with the businesses acquired in 2012 and depreciation on subsequent infrastructure additions, partially offset by the absence of increased depreciation in 2012 on certain assets in the Gulf Coast region resulting from a change in the estimated useful lives.

The decrease in SG&A is primarily due to the absence of acquisition and transition costs incurred in 2012 and a reduction in allocated administrative expenses from Williams reflecting the absence of reorganization related costs in 2012 (see Note 4 – Other Accruals of Notes to Consolidated Financial Statements).

The favorable change in other (income) expense – net within operating income primarily includes $50 million of income associated with insurance recoveries related to the Geismar Incident, $15 million of insurance recoveries related to the abandonment of certain of Eminence storage assets, and $17 million lower project development costs. Partially offsetting this income is a $15 million expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates, a $9 million accrued loss for a contingent liability associated with a pending producer claim against us recognized in the third quarter of 2013, and the absence of a $6 million gain on the sale of equipment in the second quarter of 2012.

The decrease in operating income generally reflects lower NGL production margins, higher operating costs and lower olefin production margins, partially offset by increased fee revenues, and the favorable changes in other (income) expense – net as described above.

The unfavorable changes in equity earnings (losses) are primarily due to lower equity earnings from Discovery and Aux Sable Liquid Products L.P. (Aux Sable), both driven by lower NGL margins, partially offset by higher equity earnings from Laurel Mountain driven by its higher operating results.

Interest expense decreased due to an increase in interest capitalized related to construction projects primarily at Northeast G&P and Atlantic-Gulf, partially offset by an increase in interest incurred primarily due to an increase in borrowings.

The unfavorable change in other income (expense) – net below operating income is primarily due to a $14 million charge associated with the impact of a Texas franchise tax law change in the second-quarter 2013.

Management’s Discussion and Analysis (Continued)

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Service revenues	$93	$47	$234	$108
Product sales	47	—	102	—
Segment revenues	140	47	336	108
Product costs	45	—	98	—
Depreciation and amortization expenses	33	23	94	45
Other segment costs and expenses	65	25	148	71
Equity (earnings) losses	(2)	3	(6)	12
Segment profit (loss)	$(1)	$(4)	$2	$(20)

Our Northeast G&P segment includes our Susquehanna Supply Hub (primarily resulting from the acquisition of certain assets in 2010 and the Laser Acquisition in February 2012), our Ohio Valley Midstream business (primarily resulting from the Caiman Acquisition in April 2012), and our equity-method investments in Laurel Mountain and Caiman Energy II.

Three months ended September 30, 2013 vs. three months ended September 30, 2012

Service revenues increased due to 71 percent higher gathering volumes driven by new well connections resulting from infrastructure additions and increased gathering rates associated with customer contract modifications primarily in the Susquehanna Supply Hub. Additionally, fee revenues in our Ohio Valley Midstream business increased primarily due to contributions from the processing and fractionation facilities placed in service in the latter half of 2012 and in 2013 and higher gathering volumes.

Product sales in 2013 primarily represent new NGL marketing revenues 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 new projects placed in service in the latter half of 2012 and in 2013.

Other segment costs and expenses increased primarily due to higher expenses associated with the Ohio Valley Midstream and Susquehanna Supply Hub businesses due to growth in these operations. Increases include approximately $7 million in higher employee-related costs and $7 million related to pipeline maintenance and repair costs, as well as increases in other operating costs including fuel expense and compression rentals. In addition, in 2013 we incurred a $9 million accrued loss for a contingent liability associated with a pending producer claim against us.

Equity earnings increased primarily due to higher Laurel Mountain equity earnings primarily driven by 45 percent higher gathering volumes, lower labor and related benefit costs, and lower leased compression expenses.

The favorable change in segment profit (loss) is primarily due to an increase in fee revenues in the Susquehanna Supply Hub and Ohio Valley Midstream businesses and higher Laurel Mountain equity earnings. These increases are partially offset by higher costs primarily in the Ohio Valley Midstream business in advance of the benefit of associated revenues as we continue to invest in these operations for continued growth.

Management's Discussion and Analysis (Continued)

Nine months ended September 30, 2013 vs. nine months ended September 30, 2012
Service revenues increased due to 84 percent higher gathering volumes driven by new well connections related to infrastructure additions, a full nine months of operations, and increased gathering rates associated with customer contract modifications primarily in the Susquehanna Supply Hub, as well as contributions from the processing and fractionation facilities placed in service in the latter half of 2012 and in 2013 in our Ohio Valley Midstream business.
Product sales in 2013 primarily represent new NGL marketing revenues 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 reflect a full nine months of expenses in 2013 associated with the acquired businesses and depreciation on subsequent infrastructure additions.
Other segment costs and expenses increased primarily due to higher expenses associated with the acquired businesses and the subsequent growth in these operations. This increase includes approximately $21 million in higher employee-related costs and $11 million related to pipeline maintenance and repair costs, as well as increases in other operating costs including outside services, compression rental, fuel expense, operating taxes, and materials and supplies. In addition, in 2013 we incurred a $9 million accrued loss for a contingent liability associated with a pending producer claim against us and higher allocated general and administrative support costs due to the relative growth in the businesses. These increases are partially offset by the absence of acquisition and transition costs incurred in 2012.

Equity earnings increased primarily due to higher Laurel Mountain equity earnings driven primarily by 66 percent higher gathering volumes, the receipt of an annual minimum volume commitment fee in the second quarter of 2013, and lower leased compression expenses.
The favorable change in segment profit (loss) is primarily due to an increase in fee revenues in the Susquehanna Supply Hub and Ohio Valley Midstream businesses and higher Laurel Mountain equity earnings. These increases are partially offset by higher costs primarily in our Ohio Value Midstream business in advance of the benefit of associated revenues as we continue to invest in these operations for future growth, partially offset by the absence of acquisition and transition costs incurred in 2012.
Atlantic-Gulf

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Service revenues	$346	$337	$1,057	$1,030
Product sales	217	241	697	815
Segment revenues	563	578	1,754	1,845
Product costs	199	213	636	726
Depreciation and amortization expenses	92	97	272	281
Other segment costs and expenses	152	168	451	490
Equity (earnings) losses	(17)	(24)	(53)	(68)
Segment profit	$137	$124	$448	$416
NGL margin	$17	$27	$58	$87

Management's Discussion and Analysis (Continued)

Three months ended September 30, 2013 vs. three months ended September 30, 2012

Service revenues increased primarily due to a $17 million increase in natural gas transportation fee revenues primarily associated with expansion projects placed in service in 2012 and 2013 and to the implementation of new rates for Transco in March 2013, partially offset by $8 million lower fee revenues in the eastern Gulf Coast primarily driven by natural declines in Bass Lite and Blind Faith production area volumes.

Product sales decreased primarily due to:

- An $18 million decrease in crude oil and NGL marketing revenues due primarily to lower volumes and ethane prices, partially offset by higher crude oil prices (offset in product costs).
- A $14 million decrease in revenues from our equity NGLs including an $11 million decrease related to sales volumes and a $3 million decrease associated with per-unit sales prices. Equity NGL sales volumes are 40 percent lower driven by 61 percent lower ethane volumes due primarily to lower ethane recoveries, as previously mentioned, and 21 percent lower non-ethane volumes. Average ethane and non-ethane per-unit prices decreased by 63 percent and 5 percent, respectively.
- An $8 million increase in other product sales primarily due to higher 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:

- An $18 million decrease in crude oil and NGL marketing purchases (offset in product sales).
- A $4 million decrease in costs associated with our equity NGLs primarily due to a $5 million decrease associated with lower volumes, partially offset by higher per-unit natural gas prices.
- An $8 million increase in other product costs primarily due to higher system management gas costs (offset in product sales).

Depreciation and amortization expenses decreased reflecting the absence of increased depreciation in 2012 on certain assets in the Gulf Coast region resulting from a change in the estimated useful lives.

Other segment costs and expenses decreased primarily due to lower operating costs, including compressor and pipeline maintenance and repair expenses resulting from the absence of expenses relating to the substantial completion of a natural gas pipeline integrity management plan during 2012, and insurance recoveries recognized by Transco in third-quarter 2013 related to the abandonment of certain of its Eminence storage assets. This decrease is partially offset by an expense recognized in third-quarter 2013 related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates.

Equity earnings decreased primarily due to lower equity earnings from Discovery driven by lower NGL margins resulting from decreased ethane recoveries.

Segment profit increased primarily due to higher service revenues and lower operating expenses, partially offset by lower NGL margins, an expense recognized related to the portion of the Eminence abandonment regulatory asset that will not be recovered in rates, and lower equity earnings, as previously discussed.

Nine months ended September 30, 2013 vs. nine months ended September 30, 2012

Service revenues increased primarily due to a $46 million increase in natural gas transportation fee revenues primarily associated with expansion projects placed in service in 2012 and 2013 and to the implementation of new rates for Transco in March 2013 and $5 million higher fee revenues in the western Gulf Coast primarily due to higher crude oil and natural gas volumes transported on our Perdido pipeline. These increases are partially offset by $25 million

Management's Discussion and Analysis (Continued)

lower fee revenues in the eastern Gulf Coast primarily driven by natural declines in Bass Lite and Blind Faith production area volumes.

Product sales decreased primarily due to:

- A $139 million decrease in marketing revenues reflecting a $112 million decrease in crude oil marketing sales and a $27 million decrease in NGL marketing sales. Crude oil marketing sales decreased primarily due to 28 percent lower crude volumes related to natural declines in Bass Lite and Blind Faith production area. NGL marketing sales decreased primarily due to lower NGL prices and 22 percent lower ethane volumes. Non-ethane volumes increased 13 percent, but the increase was offset by the lower non-ethane prices (offset in product costs).
- A $32 million decrease in revenues from our equity NGLs reflecting a decrease of $18 million associated with lower average realized NGL per-unit sales prices and a decrease of $14 million associated with lower equity NGL sales volumes. Average ethane and non-ethane per-unit prices decreased by 58 percent and 15 percent, respectively. Equity NGL sales volumes are 29 percent lower driven by 59 percent lower ethane volumes due primarily to lower ethane recoveries, as previously mentioned, and 3 percent lower non-ethane volumes.
- A $53 million increase in other product sales primarily due to higher 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 $139 million decrease in crude oil and NGL marketing purchases (offset in product sales).
- A $3 million decrease in costs associated with our equity NGLs primarily due to a $9 million decrease associated with lower volumes, partially offset by a $6 million increase related to higher per-unit natural gas prices.
- A $52 million increase in other product costs primarily due to higher system management gas costs (offset in product sales).

Depreciation and amortization expenses decreased reflecting the absence of increased depreciation in 2012 on certain assets in the Gulf Coast region resulting from a change in the estimated useful lives.

Other segment costs and expenses decreased primarily due to lower operating costs, including compressor and pipeline maintenance and repair expenses resulting from the absence of expenses relating to the substantial completion of a natural gas pipeline integrity management plan during 2012, lower project development costs, and insurance recoveries recognized by Transco in 2013 related to the abandonment of certain of its Eminence storage assets. These decreases are partially offset by expense recognized in 2013 related to the portion of the Eminence abandonment regulatory asset that is not expected to be recovered in rates and increased amortization of regulatory assets associated with asset retirement obligations.

Equity earnings decreased primarily due to lower equity earnings from Discovery reflecting lower NGL margins resulting from decreased ethane recoveries.

Segment profit increased primarily due to higher service revenues, lower operating expenses and project development costs, partially offset by lower NGL margins, lower equity earnings, and increased amortization of regulatory assets associated with asset retirement obligations, as previously discussed.

Management’s Discussion and Analysis (Continued)

West

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Service revenues	$266	$266	$784	$803
Product sales	212	250	602	872
Segment revenues	478	516	1,386	1,675
Product costs	111	107	304	345
Depreciation and amortization expenses	58	58	177	173
Other segment costs and expenses	102	128	350	384
Segment profit	$207	$223	$555	$773
NGL margin	$97	$140	$281	$511

Three months ended September 30, 2013 vs. three months ended September 30, 2012

Service revenues remain unchanged primarily due to a $9 million increase in natural gas transportation fee revenues at Northwest Pipeline related to new rates effective January 1, 2013. This increase was substantially offset by a $7 million decrease in gathering and processing fee revenues driven by lower volumes in the Piceance and Four Corners areas.

Product sales decreased primarily due to:

- A $45 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $35 million due to lower volumes and a $10 million decrease associated with 5 percent lower average realized non-ethane per-unit sales prices and 25 percent lower average ethane per-unit sales prices. Equity ethane sales volumes are 69 percent lower driven primarily by reduced ethane recoveries, as previously mentioned, and equity non-ethane volumes are 5 percent lower. The decrease in both ethane and non-ethane volumes is also due to a change in a certain customer's contract from percent-of-liquids to fee-based processing.
- An $8 million increase in NGL marketing revenues due primarily to higher non-ethane per-unit prices, partially offset by lower ethane volumes (substantially offset in product costs).

Product costs increased primarily due to:

- A $7 million increase in NGL marketing purchases (more than offset in product sales).
- A $2 million decrease in costs associated with our equity NGLs reflecting a $14 million decrease associated with lower natural gas volumes driven by lower ethane recoveries, partially offset by a $12 million increase driven by 30 percent higher average natural gas prices.

The decrease in other segment costs and expenses includes lower operating costs in our Four Corners area related to the consolidation of certain operations and lower general and administrative expenses.

Segment profit decreased primarily due to $43 million lower NGL margins reflecting lower NGL volumes, lower average NGL prices, and higher natural gas prices. This decrease was partially offset by lower operating and general and administrative costs.

Management's Discussion and Analysis (Continued)

Nine months ended September 30, 2013 vs. nine months ended September 30, 2012

Service revenues decreased primarily due to a $39 million decrease in gathering and processing fee revenues primarily due to a natural decline in production volumes, primarily in the Piceance basin, and severe winter weather conditions in the first quarter of 2013 which prevented producers from delivering gas. This decrease was partially offset by a $25 million increase in natural gas transportation fee revenues at Northwest Pipeline related to new rates effective January 1, 2013.

Product sales decreased primarily due to:

- A $249 million decrease in revenues from our equity NGLs primarily reflecting a decrease of $173 million due to lower volumes and a $76 million decrease associated with 13 percent lower average realized non-ethane per-unit sales prices and 47 percent lower average ethane per-unit sales prices. Equity ethane sales volumes are 80 percent lower driven by reduced ethane recoveries, as previously mentioned, and equity non-ethane volumes are 7 percent lower due primarily to a change in a certain customer's contract from percent-of-liquids to fee-based processing and periods of local severe winter weather conditions in the first quarter of 2013 which prevented producers from delivering gas.
- A $21 million decrease in NGL marketing revenues due primarily to lower ethane volumes (more than offset in product costs).

Product costs decreased primarily due to:

- A $22 million decrease in NGL marketing purchases (substantially offset in product sales).
- A $19 million decrease in costs associated with our equity NGLs reflecting a $53 million decrease associated with lower natural gas volumes driven by lower ethane recoveries, partially offset by a $34 million increase related to a 36 percent increase in average natural gas prices.

Other segment costs and expenses decreased primarily due to lower allocated general and administrative support costs due to relative growth in the other segments, as well as lower operating costs in our Four Corners area related to the consolidation of certain operations.

Segment profit decreased primarily due to $230 million lower NGL margins reflecting lower NGL volumes, lower average NGL prices, and higher average natural gas prices, as well as the decrease in gathering and processing fee revenues, partially offset by lower general and administrative expenses and increased natural gas transportation revenues.

Management's Discussion and Analysis (Continued)

NGL & Petchem Services

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Service revenues	$27	$27	$81	$75
Product sales	665	968	2,376	3,139
Segment revenues	692	995	2,457	3,214
Product costs	652	880	2,154	2,932
Depreciation and amortization expenses	7	7	22	16
Other segment (income) costs and expenses	(17)	31	47	95
Equity (earnings) losses	(12)	(9)	(25)	(31)
Segment profit	$62	$86	$259	$202
Olefins margin	$1	$77	$207	$221
Marketing margin	10	12	10	(20)

Three months ended September 30, 2013 vs. three months ended September 30, 2012

Product sales decreased primarily due to:

- A $195 million decrease in marketing revenues due primarily to lower NGL volumes and prices, partially offset by higher natural gas volumes and prices. These changes are substantially offset in product costs.
- A $114 million decrease in olefin sales primarily due to the loss of production as a result of the Geismar Incident.

Product costs decreased primarily due to:

- A $193 million decrease in NGL marketing purchases, partially offset by higher natural gas marketing purchases (more than offset in product sales).
- A $38 million decrease in feedstock purchases primarily due to the loss of production as a result of the Geismar Incident.

Other segment (income) costs and expenses improved primarily due to the recognition of $50 million of income associated with insurance recoveries related to the Geismar Incident during the third quarter of 2013 and the absence of $4 million of furnace repair expenses in 2012. Partially offsetting this income is $4 million of costs incurred under our insurance deductibles resulting from the Geismar Incident.

Equity earnings increased primarily due to higher equity earnings from Aux Sable driven by higher operating results.

Segment profit decreased primarily due to lower olefin product margins, partially offset by the $50 million insurance recovery discussed above. Olefin product margins are $76 million lower including $59 million lower ethylene product margins primarily due to 96 percent lower volumes sold due to the loss of production as a result of the Geismar Incident.

Management's Discussion and Analysis (Continued)

Nine months ended September 30, 2013 vs. Nine months ended September 30, 2012

Product sales decreased primarily due to:

- A $631 million decrease in marketing revenues due primarily to lower NGL volumes and prices, partially offset by higher natural gas volumes and prices. These changes are more than offset in product costs.
- A $132 million decrease in olefin sales due to $169 million related to lower volumes, partially offset by $37 million associated with higher per-unit sales prices. Olefin production volumes are lower primarily due to the loss of production as a result of the Geismar Incident, partially offset by the absence of 7 days of unplanned turbine maintenance in April 2012 and changes in inventory management. Ethylene prices averaged 21 percent higher, partially offset by 34 percent lower butadiene prices.

Product costs decreased primarily due to:

- A $661 million decrease in NGL marketing purchases partially offset by increased natural gas marketing purchases (substantially offset in product sales).
- A $118 million decrease in feedstock purchases due to $90 million of lower volumes, primarily due to the loss of production as a result of the Geismar Incident, and $28 million lower feedstock costs, reflecting 25 percent lower average per-unit ethylene feedstock prices.

Other segment (income) costs and expenses improved primarily due to the recognition of $50 million of income associated with insurance recoveries related to the Geismar Incident during the third quarter of 2013 related to the Geismar Incident and the absence of $4 million of furnace repair expenses in 2012. Partially offsetting this income is $10 million of costs incurred under our insurance deductibles resulting from the Geismar Incident.

Equity earnings decreased primarily due to lower equity earnings from Aux Sable driven by lower NGL margins.

Segment profit increased primarily due to the $50 million insurance recovery discussed above, higher marketing margins and the absence of $4 million of furnace repair expenses in 2012, partially offset by lower olefin product margins, lower equity earnings and the $10 million of cost incurred under our insurance deductibles discussed above. Marketing margins are $28 million higher primarily due to the absence of losses recognized in the second quarter of 2012 which were driven by significant declines in NGL prices while product was in transit. Olefin margins are $14 million lower including $67 million lower ethylene volumes offset by $41 million higher ethylene prices and $25 million lower ethane costs.

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 and maintaining investment-grade credit metrics. Our plan for 2013 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 for 2013:

- We increased our per-unit quarterly distribution with respect to the third quarter of 2013 from $0.8625 to $0.8775. We expect to increase quarterly limited partner cash distributions in total by approximately 9 percent in 2013 and 6 percent in 2014 and 2015, which is within the previously disclosed range of 6 percent to 8 percent for 2014 and 2015.
- In May 2013, Williams agreed to waive incentive distributions of up to $200 million over the next four quarters to support our cash distribution metrics as our large platform of growth projects moves toward completion. We will realize a $90 million benefit from the waived incentive distributions with our November 2013 distribution.
- 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 revolver and/or commercial paper program. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $1.98 billion and $2.01 billion in 2013. 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 2013. 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;
- Cash proceeds from issuances of debt and/or equity securities;
- Use of our revolver and/or commercial paper program.

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;

Management's Discussion and Analysis (Continued)

- Interest on our long-term debt;
- Quarterly distributions to our unitholders and/or general partner.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations;
- Limited availability of capital due to a change in our financial condition, interest rates, market or industry conditions;
- Sustained reductions in energy commodity prices and margins from the range of current expectations;
- Significant physical damage to facilities, especially damage to offshore facilities by named windstorms;
- Unexpected significant increases in capital expenditures or delays in capital project execution.

As of September 30, 2013, we had a working capital deficit (current liabilities, inclusive of commercial paper borrowings, in excess of current assets) of $955 million. However, we note the following about our available liquidity.

Available Liquidity	September 30, 2013 (Millions)
Cash and cash equivalents	$ 64
Capacity available under our $2.5 billion five-year revolver (expires July 31, 2018), less amounts outstanding under the $2 billion commercial paper program (1)	2,129
	$ 2,193

(1) On July 31, 2013, we amended our $2.4 billion revolver to increase the aggregate commitments to $2.5 billion and extend the maturity date to July 31, 2018. The full amount of the revolver 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 revolver to the extent not otherwise utilized by the other co-borrowers. At September 30, 2013, we are in compliance with the financial covenants associated with this revolver and commercial paper program. In managing our available liquidity, we do not expect a maximum outstanding amount under this commercial paper program in excess of the capacity available under our revolver.

Commercial Paper

In March 2013, we initiated a commercial paper program. The program allows a maximum outstanding amount at any time of $2 billion of unsecured commercial paper notes. The maturities of the commercial paper notes vary but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or, alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. Proceeds from these notes are used for general partnership purposes, including funding capital expenditures, working capital, and partnership distributions. At September 30, 2013, we had $371 million in commercial paper outstanding.

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. Our more significant equity method investees include: Aux Sable, Caiman II, Discovery, Gulfstream, Laurel Mountain, and OPPL.

Management's Discussion and Analysis (Continued)

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 September 30, 2013, no common units have been issued under this registration.

Equity Offerings

In August 2013, we completed an equity issuance of 21,500,000 common units. Subsequently, the underwriters exercised their option to purchase 3,225,000 common units. The net proceeds of approximately $1.2 billion were used to repay amounts outstanding under our commercial paper program, to fund capital expenditures, and for general partnership purposes.

In March 2013, we completed an equity issuance of 14,250,000 common units, including 3,000,000 common units sold to Williams in a private placement. Subsequently, the underwriters exercised their option to purchase 1,687,500 common units. The net proceeds of approximately $760 million were used to repay amounts outstanding under our revolver.

Credit Ratings

The table below presents our current credit ratings and outlook on our senior unsecured long-term debt.

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

With respect to Standard and Poor's, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard and Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard and Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

With respect to Moody's, a rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. The "1", "2", and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" indicates a ranking at the lower end of the category.

With respect to Fitch, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. Fitch may add a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

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 September 30, 2013, we estimate that a downgrade to a rating below investment grade could require us to post up to $233 million in additional collateral with third parties.

Management's Discussion and Analysis (Continued)

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 2013. Included are gross increases to our property, plant, and equipment, including changes related to accounts payable and accrued liabilities:

Segment	Maintenance		Expansion		Total	
	2013 Estimate	Nine months ended September 30, 2013	2013 Estimate	Nine months ended September 30, 2013	2013 Estimate	Nine months ended September 30, 2013
	(Millions)					
Northeast G&P	$10	$6	$1,625	$1,260	$1,635	$1,266
Atlantic-Gulf	155	110	1,150	741	1,305	851
West	120	65	145	104	265	169
NGL & Petchem Services	20	12	380	219	400	231
Other	—	4	—	—	—	4
Total	$305	$197	$3,300	$2,324	$3,605	$2,521

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 $0.8625 with respect to the second quarter of 2013 to $0.8775 per unit, which resulted in a third quarter 2013 distribution of approximately $442 million that will be paid on November 12, 2013, to the general and limited partners of record at the close of business on November 5, 2013. (See Note 3 – Allocation of Net Income and Distributions of Notes to Consolidated Financial Statements.)

Sources (Uses) of Cash

	Nine months ended September 30,	
	2013	2012
	(Millions)	
Net cash provided (used) by:		
Operating activities	$1,591	$1,476
Financing activities	897	2,429
Investing activities	(2,444)	(3,700)
Increase (decrease) in cash and cash equivalents	$44	$205

Management's Discussion and Analysis (Continued)

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. The increase in net cash provided by operating activities is primarily due to proceeds from insurance recoveries on the Eminence Storage Field leak and Geismar Incident and net favorable changes in operating working capital.

Financing activities

Significant transactions include:

- $370 million net proceeds received in 2013 from commercial paper issuances;
- $1.705 billion in 2013 and $960 million in 2012 received from revolver borrowings;
- $745 million net proceeds received from our August 2012 public offering of $750 million of senior unsecured notes due 2022;
- $395 million net proceeds received from Transco's July 2012 issuance of $400 million of senior unsecured notes due 2042;
- $2.080 billion in 2013 and $960 million in 2012 paid on revolver borrowings;
- $325 million paid to retire Transco's 8.875 percent notes that matured in July 2012;
- $1.962 billion received from our equity offerings in 2013, including $143 million received from Williams, which was used to repay revolver borrowings;
- $1.559 billion received from our equity offerings in 2012 which was used to fund a portion of the cash purchase price of the Caiman Acquisition, for capital expenditures and for general partnership purposes;
- $1 billion received from Williams in 2012 for common units issued, used for the funding of a portion of the cash purchase price of the Caiman Acquisition;
- $1.404 billion, including $1.073 billion to Williams, in 2013 and $1.046 billion, including $810 million to Williams, in 2012 related to quarterly cash distributions paid to limited partner unitholders and our general partner;
- $300 million received in contributions from noncontrolling interests in 2013.

Investing activities

Significant transactions include:

- Capital expenditures of $2.117 billion in 2013 and $1.449 billion in 2012;
- $1.72 billion paid, net of purchase price adjustments, for the Caiman Acquisition in 2012;
- $325 million paid, net of cash acquired in the transaction, for entities acquired in the Laser Acquisition in 2012;
- Purchases of and contributions to our equity method investments of $344 million in 2013 and $282 million in 2012.

Management's Discussion and Analysis (Continued)

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

We have various other guarantees and commitments which are disclosed in Note 8 – Fair Value Measurements 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 nine months of 2013.

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 is also 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.
Third-Quarter 2013 Changes in Internal Controls
There have been no changes during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

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.

The New Mexico Environment Department's Air Quality Bureau (NMED) issued a Notice of Violation to Williams Four Corners LLC (Four Corners) on October 23, 2012, as revised on February 7, 2013, for the El Cedro Gas Treating Plant related to the plant's use of a standby generator and the timing of periodic testing. Settlement negotiations with the NMED to resolve the alleged violations are ongoing, with the NMED offering on April 5, 2013, to settle for $162,711.

On January 18, 2013, the NMED issued a Notice of Violation to Four Corners relating to permitting issues for condensate storage tanks at the La Jara Compressor Station. Four Corners has been in discussions with the NMED about such permitting issues since early 2011. The NMED withdrew the Notice of Violation on September 9, 2013.

On February 12, 2013, the NMED issued a Notice of Violation to Four Corners related to the alleged modification of turbine units and a separator tank and alleged failure to conduct performance tests on certain facilities at the La Jara Compressor Station. Four Corners has been in discussions with the NMED since 2012 regarding the separator tank and other permitting issues. Settlement negotiations to resolve the issues are ongoing, with the NMED offering on June 10, 2013 to settle for $1,336,564.

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, 2012, 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 olefins 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 cash distributions to be materially different than we project.

Our projections of financial results and expected levels of cash distributions are based on numerous assumptions and estimates, including but not limited to the time required to return our Geismar, Louisiana olefins 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. Our financial results and levels of cash distributions could be materially different than we project if our assumptions and estimates related to the incident are materially different than actual outcomes.

Item 5. Other Information

Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year.

On May 7, 2013, we issued a press release announcing our financial results for the quarter ended March 31, 2013 (First Quarter Press Release). The First Quarter Press Release noted that Williams had agreed to waive IDRs of up to $200 million over the next four quarters to support our cash distribution metrics. Our general partner is the sole holder of the IDRs. To effect such waiver of the IDRs, on October 25, 2013, our general partner executed Amendment No. 10 to our Amended and Restated Agreement of Limited Partnership (Amendment No. 10). Amendment No. 10 provides that our general partner may, with respect to each quarter ending on or before March 31, 2014, reduce distributions of available cash to the holder of the IDRs in an amount or percentage as determined by our general partner. Our general partner is a wholly owned subsidiary of Williams. The description of Amendment No. 10 in this Item 5 is qualified in its entirety by reference to the copy of Amendment No. 10 filed in Exhibit 3.3 to this report, which is incorporated herein by reference.

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, and 10.
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	—	First Amended & Restated Credit Agreement, dated as of July 31, 2013, by and among Williams Partners L.P., Northwest Pipeline LLC and Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank N.A., as Administrative Agent (filed on July 31, 2013 as Exhibit 10 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-32599) and incorporated herein by reference).
*Exhibit 10.2	—	Director Compensation Policy dated November 29, 2005, as revised August 27, 2013.
*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)

October 31, 2013

EXHIBIT INDEX

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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, and 10.
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	—	First Amended & Restated Credit Agreement, dated as of July 31, 2013, by and among Williams Partners L.P., Northwest Pipeline LLC and Transcontinental Gas Pipe Line Company, LLC, as co-borrowers, the lenders named therein, and Citibank N.A., as Administrative Agent (filed on July 31, 2013 as Exhibit 10 to Williams Partners L.P.'s quarterly report on Form 10-Q (File No. 001-32599) and incorporated herein by reference).
*Exhibit 10.2	—	Director Compensation Policy dated November 29, 2005, as revised August 27, 2013.
*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