UGI CORP /PA/
Form 10-Q
August 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
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 1-11071
UGI CORPORATION
(Exact name of registrant as specified in its charter)

Pennsylvania (State or other jurisdiction of incorporation or organization)	23-2668356 (I.R.S. Employer Identification No.)
460 North Gulph Road, King of Prussia, PA (Address of principal executive offices)	19406 (Zip Code)

(610) 337-1000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
At July 31, 2015, there were 172,778,018 shares of UGI Corporation Common Stock, without par value, outstanding.

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UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(Millions of dollars)

	June 30, 2015	September 30, 2014	June 30, 2014
ASSETS			
Current assets:			
Cash and cash equivalents	$385.9	$419.5	$438.4
Restricted cash	45.2	16.6	5.9
Accounts receivable (less allowances for doubtful accounts of $40.3, $39.1 and $52.5, respectively)	728.2	684.7	785.4
Accrued utility revenues	7.7	14.3	8.0
Inventories	208.7	423.0	332.0
Deferred income taxes	71.6	10.1	9.1
Utility regulatory assets	2.8	13.2	9.4
Derivative instruments	27.3	14.5	12.4
Prepaid expenses and other current assets	80.7	67.1	38.3
Total current assets	1,558.1	1,663.0	1,638.9
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,773.6, $2,633.0 and $2,702.3, respectively)	4,923.7	4,543.7	4,543.4
Goodwill	2,927.7	2,833.4	2,885.1
Intangible assets, net	628.5	576.4	590.3
Derivative instruments	15.6	12.5	1.3
Other assets	466.4	464.0	418.7
Total assets	$10,520.0	$10,093.0	$10,077.7
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$83.3	$77.2	$78.4
Short-term borrowings	68.0	210.8	96.5
Accounts payable	356.8	459.8	403.8
Derivative instruments	109.6	40.2	26.2
Other current liabilities	721.7	642.9	609.3
Total current liabilities	1,339.4	1,430.9	1,214.2
Long-term debt	3,628.3	3,433.6	3,477.8
Deferred income taxes	1,162.9	1,005.1	986.2
Deferred investment tax credits	3.7	3.9	4.0
Derivative instruments	25.7	16.6	16.9
Other noncurrent liabilities	624.4	539.7	497.8
Total liabilities	6,784.4	6,429.8	6,196.9
Commitments and contingencies (Note 9)			
Equity:			
UGI Corporation stockholders’ equity:			
UGI Common Stock, without par value (authorized—450,000,000 shares; issued—173,806,991, 173,770,641 and 173,746,041 shares, respectively)	1,208.4	1,215.6	1,216.0
Retained earnings	1,685.3	1,509.4	1,566.7
Accumulated other comprehensive (loss) income	(112.2)	(21.2)	25.4
Treasury stock, at cost	(33.0)	(44.7)	(37.1)

Total UGI Corporation stockholders' equity	2,748.5	2,659.1	2,771.0
Noncontrolling interests, principally in AmeriGas Partners	987.1	1,004.1	1,109.8
Total equity	3,735.6	3,663.2	3,880.8
Total liabilities and equity	$ 10,520.0	$ 10,093.0	$ 10,077.7

See accompanying notes to condensed consolidated financial statements.

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CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(Millions of dollars, except per share amounts)

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$1,148.1	$1,486.7	$5,608.3	$6,965.9
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	586.4	926.5	3,196.4	4,357.7
Operating and administrative expenses	419.8	415.9	1,322.1	1,339.4
Utility taxes other than income taxes	3.7	3.7	12.6	12.7
Depreciation	77.2	74.6	226.8	230.0
Amortization	15.3	15.4	44.7	41.7
Other operating income, net	(10.4)	(12.1)	(35.8)	(30.6)
	1,092.0	1,424.0	4,766.8	5,950.9
Operating income	56.1	62.7	841.5	1,015.0
Loss from equity investees	—	(0.1)	(1.1)	(0.1)
Interest expense	(67.5)	(60.1)	(184.7)	(178.9)
(Loss) income before income taxes	(11.4)	2.5	655.7	836.0
Income tax expense	(4.5)	(15.2)	(189.2)	(243.4)
Net (loss) income	(15.9)	(12.7)	466.5	592.6
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	25.5	33.3	(176.3)	(235.6)
Net income attributable to UGI Corporation	$9.6	$20.6	$290.2	$357.0
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$0.06	$0.12	$1.68	$2.07
Diluted	$0.05	$0.12	$1.65	$2.04
Average common shares outstanding (thousands):				
Basic	173,136	173,055	173,060	172,682
Diluted	175,580	175,572	175,665	175,097
Dividends declared per common share	$0.2275	$0.1967	$0.6625	$0.5733

See accompanying notes to condensed consolidated financial statements.

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CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(Millions of dollars)

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Net (loss) income	$(15.9)	$(12.7)	$466.5	$592.6
Other comprehensive income (loss):				
Net (losses) gains on derivative instruments (net of tax of $2.4, $0.6, $(11.9) and $(6.5), respectively)	(4.8)	(0.6)	23.1	46.2
Reclassifications of net losses (gains) on derivative instruments (net of tax of $(1.9), $(1.3), $(2.3) and $4.0, respectively)	0.5	(1.5)	0.7	(46.7)
Foreign currency adjustments (net of tax of $(55.3), $0.0, $(4.7) and $(3.1), respectively)	(23.0)	(0.2)	(118.0)	11.5
Benefit plans (net of tax of $(0.1), $(0.2), $(0.7) and $(0.2), respectively)	0.4	0.2	1.4	0.8
Other comprehensive (loss) income	(26.9)	(2.1)	(92.8)	11.8
Comprehensive (loss) income	(42.8)	(14.8)	373.7	604.4
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	25.6	36.5	(174.5)	(230.4)
Comprehensive (loss) income attributable to UGI Corporation	$(17.2)	$21.7	$199.2	$374.0

See accompanying notes to condensed consolidated financial statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(Millions of dollars)

	Nine Months Ended June 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$466.5	$592.6
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	271.5	271.7
Deferred income tax (benefit) expense, net	(39.9)	21.2
Provision for uncollectible accounts	26.2	38.2
Unrealized losses on derivative instruments	109.5	3.1
Other, net	26.5	(4.9)
Net change in:		
Accounts receivable and accrued utility revenues	54.4	(56.4)
Inventories	211.0	34.8
Utility deferred fuel and power costs, net of changes in unsettled derivatives	59.4	(17.6)
Accounts payable	(171.2)	(40.8)
Other current assets	(3.7)	11.2
Other current liabilities	(42.1)	5.0
Net cash provided by operating activities	968.1	858.1
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(330.4)	(325.5)
Acquisitions of businesses, net of cash acquired	(428.2)	(23.3)
(Increase) decrease in restricted cash	(28.6)	2.4
Other, net	12.2	9.0
Net cash used by investing activities	(775.0)	(337.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(114.3)	(98.6)
Distributions on AmeriGas Partners publicly held Common Units	(185.3)	(176.9)
Issuances of debt	652.6	175.0
Repayments of debt	(406.4)	(236.8)
Decrease in short-term borrowings	(154.2)	(74.6)
Receivables Facility net borrowings (repayments)	12.5	(57.0)
Issuances of UGI Common Stock	10.3	7.0
Repurchases of UGI Common Stock	(17.3)	(21.4)
Other	(5.2)	7.9
Net cash used by financing activities	(207.3)	(475.4)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(19.4)	3.8
Cash and cash equivalents (decrease) increase	$(33.6)	$49.1
Cash and cash equivalents:		
End of period	$385.9	$438.4
Beginning of period	419.5	389.3
(Decrease) increase	$(33.6)	$49.1

See accompanying notes to condensed consolidated financial statements.

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CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(Millions of dollars)

	Nine Months Ended June 30, 2015	2014
Common stock, without par value		
Balance, beginning of period	$1,215.6	$1,208.1
Common Stock issued in connection with employee and director plans (including (losses) gains on treasury stock transactions), net of tax withheld	(18.6)	(9.6)
Excess tax benefits realized on equity-based compensation	6.3	8.4
Equity-based compensation expense	11.7	9.1
Loss from acquisition of noncontrolling interests through business combination	(6.6)	—
Balance, end of period	$1,208.4	$1,216.0
Retained earnings		
Balance, beginning of period	$1,509.4	$1,308.3
Net income attributable to UGI Corporation	290.2	357.0
Cash dividends on Common Stock	(114.3)	(98.6)
Balance, end of period	$1,685.3	$1,566.7
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$(21.2)	$8.4
Net gains on derivative instruments, net of tax	23.1	12.3
Reclassification of net losses (gains) on derivative instruments, net of tax	2.5	(7.6)
Benefit plans, net of tax	1.4	0.8
Foreign currency, net of tax	(118.0)	11.5
Balance, end of period	$(112.2)	$25.4
Treasury stock		
Balance, beginning of period	$(44.7)	$(32.3)
Common stock issued in connection with employee and director plans, net of tax withheld	33.2	46.7
Repurchases of Common Stock	(17.3)	(21.4)
Reacquired common stock - employee and director plans	(4.2)	(30.1)
Balance, end of period	$(33.0)	$(37.1)
Total UGI Corporation stockholders’ equity	$2,748.5	$2,771.0
Noncontrolling interests		
Balance, beginning of period	$1,004.1	$1,055.4
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	176.3	235.6
Net gains on derivative instruments	—	33.9
Reclassification of net gains on derivative instruments	(1.8)	(39.1)
Dividends and distributions	(185.8)	(176.9)
Change in noncontrolling interests as a result of business combination	(5.2)	—
Other	(0.5)	0.9
Balance, end of period	$987.1	$1,109.8
Total equity	$3,735.6	$3,880.8

See accompanying notes to condensed consolidated financial statements.

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Note 1 — Nature of Operations

UGI Corporation (“UGI”) is a holding company that, through subsidiaries and affiliates, distributes, stores, transports and markets energy products and related services. In the United States, we (1) are the general partner and own limited partner interests in a retail propane marketing and distribution business; (2) own and operate natural gas and electric distribution utilities; (3) own all or a portion of electricity generation facilities; and (4) own and operate an energy marketing, midstream infrastructure, storage, natural gas gathering, natural gas production and energy services business. Internationally, we market and distribute propane and other liquefied petroleum gases (“LPG”) in Europe and China. We refer to UGI and its consolidated subsidiaries collectively as “the Company”, “we” or “us”.

We conduct a domestic propane marketing and distribution business through AmeriGas Partners, L.P. (“AmeriGas Partners”). AmeriGas Partners is a publicly traded limited partnership that conducts a national propane distribution business through its principal operating subsidiary AmeriGas Propane, L.P. (“AmeriGas OLP”), which is referred to herein as the “Operating Partnership.” AmeriGas Partners and AmeriGas OLP are Delaware limited partnerships. UGI’s wholly owned second-tier subsidiary, AmeriGas Propane, Inc. (the “General Partner”), serves as the general partner of AmeriGas Partners and AmeriGas OLP. We refer to AmeriGas Partners and its subsidiaries together as the “Partnership” and the General Partner and its subsidiaries, including the Partnership, as “AmeriGas Propane.” At June 30, 2015, the General Partner held a 1% general partner interest and a 25.3% limited partner interest in AmeriGas Partners and held an effective 27.1% ownership interest in AmeriGas OLP. Our limited partnership interest in AmeriGas Partners comprises 23,756,882 AmeriGas Partners Common Units (“Common Units”). The remaining 73.7% interest in AmeriGas Partners comprises 69,132,661 Common Units held by the public. The General Partner also holds incentive distribution rights that entitle it to receive distributions from AmeriGas Partners in excess of its 1% general partner interest under certain circumstances as further described in Note 15 of our Annual Report on Form 10-K for the fiscal year ended September 30, 2014 (the “Company’s 2014 Annual Report”). Incentive distributions received by the General Partner during the nine months ended June 30, 2015 and 2014 were $21.7 and $17.3, respectively.

Our wholly owned subsidiary, UGI Enterprises, Inc. (“Enterprises”), through subsidiaries, conducts (1) an LPG distribution business in France, Belgium, the Netherlands and Luxembourg (“Antargaz”); (2) an LPG distribution business in central, northern and eastern Europe (“Flaga”); (3) an LPG distribution business in the United Kingdom (“AvantiGas”); and (4) an LPG distribution business in the Nantong region of China. We refer to our foreign LPG operations collectively as “UGI International.” On May 29, 2015, UGI France (formerly Bordeaux Holding), an indirect wholly owned subsidiary of UGI, purchased all of the outstanding shares of Totalgaz (referred to as Finagaz after the acquisition), a retail distributor of LPG in France. The assets and liabilities and results of operations of Finagaz are included in our Antargaz reportable segment (see Notes 14 and 15).

Enterprises, through UGI Energy Services, LLC and its subsidiaries, conducts an energy marketing, midstream infrastructure, storage, natural gas gathering, natural gas production and energy services business primarily in the Mid-Atlantic and Northeast U.S. In addition, UGI Energy Services, LLC’s wholly owned subsidiary, UGI Development Company (“UGID”), owns all or a portion of electricity generation facilities principally located in Pennsylvania. These businesses are referred to herein collectively as “Midstream & Marketing.” UGI Energy Services, LLC is referred to herein as “Energy Services.” Enterprises also conducts heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses in the Mid-Atlantic region through first-tier subsidiaries.

Our natural gas distribution utility business (“Gas Utility”) is conducted through our wholly owned subsidiary, UGI Utilities, Inc. (“UGI Utilities”), and its subsidiaries, UGI Penn Natural Gas, Inc. (“PNG”) and UGI Central Penn Gas, Inc. (“CPG”). UGI Utilities, PNG and CPG own and operate natural gas distribution utilities in eastern, northeastern and central Pennsylvania and in a portion of one Maryland county. UGI Utilities also owns and operates an electric distribution utility in northeastern Pennsylvania (“Electric Utility”). UGI Utilities’ natural gas distribution utility is referred to as “UGI Gas.” Gas Utility is subject to regulation by the Pennsylvania Public Utility Commission (“PUC”) and, with respect to a small service territory in one Maryland county, the Maryland Public Service Commission. Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as “Utilities.”

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Note 2 — Summary of Significant Accounting Policies

Our condensed consolidated financial statements include the accounts of UGI and its controlled subsidiary companies, which, except for the Partnership, are majority owned. We report the public's limited partner interests in the Partnership, and outside ownership interests in other consolidated but less than 100%-owned subsidiaries, as noncontrolling interests. We eliminate intercompany accounts and transactions when we consolidate. Entities in which we do not have control but have significant influence over operating and financial policies are accounted for by the equity method. Investments in business entities that are not publicly traded and in which we hold less than 20% of voting rights are accounted for using the cost method. Undivided interests in natural gas production assets and an electricity generation facility are consolidated on a proportionate basis.

The accompanying condensed consolidated financial statements are unaudited and have been prepared in accordance with the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). They include all adjustments that we consider necessary for a fair statement of the results for the interim periods presented. Such adjustments consisted only of normal recurring items unless otherwise disclosed. The September 30, 2014, condensed consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by accounting principles generally accepted in the United States of America ("GAAP").

These financial statements should be read in conjunction with the financial statements and related notes included in the Company's 2014 Annual Report. Due to the seasonal nature of our businesses, the results of operations for interim periods are not necessarily indicative of the results to be expected for a full year.

Earnings Per Common Share. Basic earnings per share attributable to UGI Corporation shareholders reflect the weighted-average number of common shares outstanding. Diluted earnings per share attributable to UGI Corporation include the effects of dilutive stock options and common stock awards.

Shares used in computing basic and diluted earnings per share are as follows:

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Denominator (thousands of shares):				
Average common shares outstanding for basic computation	173,136	173,055	173,060	172,682
Incremental shares issuable for stock options and awards	2,444	2,517	2,605	2,415
Average common shares outstanding for diluted computation	175,580	175,572	175,665	175,097

Derivative Instruments. Derivative instruments are reported in the Condensed Consolidated Balance Sheets at their fair values, unless the derivative instruments qualify for the normal purchase and normal sale ("NPNS") exception under GAAP. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is designated and qualifies for hedge accounting.

Certain of our derivative instruments are designated and qualify as cash flow hedges or net investment hedges. For cash flow hedges, changes in the fair values of the derivative instruments are recorded in accumulated other comprehensive income (“AOCI”) or noncontrolling interests, to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. We discontinue cash flow hedge accounting if the forecasted transaction is determined to be no longer probable. Gains and losses on net investment hedges that relate to our foreign operations are included in AOCI until such foreign net investment is sold or liquidated. Unrealized gains and losses on certain commodity derivative instruments used by Gas Utility and Electric Utility are included in regulatory assets or liabilities because it is probable such gains or losses will be recoverable from, or refundable to, customers.

Effective October 1, 2014, UGI International determined on a prospective basis that it would not elect cash flow hedge accounting for its commodity derivative transactions and also de-designated its then-existing commodity derivative instruments accounted for as cash flow hedges. Also effective October 1, 2014, AmeriGas Propane de-designated its remaining commodity derivative

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instruments accounted for as cash flow hedges. Previously, AmeriGas Propane had discontinued cash flow hedge accounting for all commodity derivative instruments entered into beginning April 1, 2014. Midstream & Marketing has not applied cash flow hedge accounting for its commodity derivative instruments during any of the periods presented. Substantially all realized and unrealized gains and losses on commodity derivative instruments are recorded in cost of sales or revenues. For additional information on our derivative instruments, see Note 12.

Reclassifications. Certain prior period amounts have been reclassified to conform to current period presentation.

Consolidated Effective Income Tax Rate. UGI's consolidated effective income tax rate, defined as total income tax (expense) or benefit as a percentage of income (loss) before income taxes, includes amounts associated with noncontrolling interests in the Partnership, which principally comprises AmeriGas Partners and AmeriGas OLP. AmeriGas Partners and AmeriGas OLP are not directly subject to federal income taxes. As a result, UGI's consolidated effective income tax rate is affected by the amount of income (loss) before income taxes attributable to noncontrolling interests in the Partnership not subject to income taxes.

Use of Estimates. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and costs. These estimates are based on management's knowledge of current events, historical experience and various other assumptions that are believed to be reasonable under the circumstances. Accordingly, actual results may be different from these estimates and assumptions.

Correction of Prior Period Error in Other Comprehensive Income
During the three months ended June 30, 2015, the Company recorded a $57.8 decrease to other comprehensive income related to prior periods by reducing the amount of net deferred tax assets that had been previously recognized for (1) foreign currency adjustments related to foreign subsidiaries whose undistributed earnings are considered indefinitely reinvested, and (2) foreign currency adjustments related to intercompany loans between a U.S. domiciled entity and its foreign branch that is considered disregarded for tax purposes and for which income taxes will not be payable. Accounting Standards Codification No. 740, "Income Taxes," provides an exception to recording deferred tax attributes associated with these components of comprehensive income. Previously, the Company had incorrectly recorded deferred taxes on these currency adjustments. The Company has evaluated the effects of the errors, both qualitatively and quantitatively, and concluded that they did not have a material impact on any prior annual or quarterly consolidated financial statement. The Company also evaluated and concluded that the impact of recording the cumulative effect of the correction of the error as of April 1, 2015 (the beginning of the three-month period ended June 30, 2015) is not material to the financial statements for the three or nine months ended June 30, 2015 and is not expected to be material to the full year results for Fiscal 2015.
The impact to other comprehensive income for the three and nine months ended June 30, 2015 resulting from the correction of these errors is as follows:

	Three Months Ended June 30, 2015	Nine Months Ended June 30, 2015
Reported other comprehensive loss	$(26.9)	$(92.8)
Correction of error in deferred taxes related to prior periods	57.8	10.7
Other comprehensive income (loss) excluding impact of correction	$30.9	$(82.1)

Note 3 — Accounting Changes

Accounting Standards Not Yet Adopted

Measurement of Inventory. In July 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2015-11, "Simplifying the Measurement of Inventory." This ASU amends existing guidance to require inventory to be measured at the lower of cost or net realizable value. Entities will continue to apply their existing impairment models to inventories that are accounted for using “last-in, first-out” and the “retail inventory” methods. The amendments in this ASU are effective for annual periods beginning after December 15, 2016 (Fiscal 2018) including interim periods within those

fiscal years. Early adoption is permitted. Entities will apply the new guidance prospectively after the date of adoption. The Company is in the process of assessing the impact on its financial statements, if any, from the adoption of the new guidance.
Debt Issuance Costs. In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This ASU amends existing guidance to require the presentation of debt issuance costs in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of a deferred charge. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2015. Early adoption is permitted. Entities will apply the new guidance retrospectively to all periods presented. The Company expects to adopt the new guidance in the fourth quarter of Fiscal 2015. The adoption of the new guidance is not expected to have a material impact on the Company's financial statements.

Consolidation. In February 2015, the FASB issued ASU No. 2015-02, "Amendments to the Consolidation Analysis." This ASU provides new guidance regarding whether a reporting entity should consolidate certain types of legal entities. Among other things, the new guidance modifies the evaluation of whether limited partnerships and similar entities are variable interest entities ("VIEs") or voting interest entities, and also eliminates the presumption that a general partner should consolidate a limited partnership. The new guidance also affects the consolidation analysis of reporting entities that are involved with VIEs including those that have fee arrangements and related party relationships. The new guidance is effective for the Company beginning in Fiscal 2017. Early adoption is permitted. The Company is in the process of assessing the impact on its financial statements, if any, from the adoption of the new guidance.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers." This ASU supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") 605, "Revenue Recognition," and most industry-specific guidance included in the ASC. The standard requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This standard is effective for the Company for interim and annual periods beginning October 1, 2017 (Fiscal 2018) and allows for either full retrospective adoption or modified retrospective adoption. On July 9, 2015, the FASB voted to delay the effective date by one year. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our consolidated financial statements.

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2015	September 30, 2014	June 30, 2014
Non-utility LPG and natural gas	$124.6	$283.6	$222.6
Gas Utility natural gas	19.2	82.7	45.7
Materials, supplies and other	64.9	56.7	63.7
Total inventories	$208.7	$423.0	$332.0

At June 30, 2015, UGI Utilities is a party to three principal storage contract administrative agreements ("SCAAs") having terms of three years. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the terms of the SCAAs. The historical cost of natural gas storage inventories released under the SCAAs, which represents a portion of Gas Utility's total natural gas storage inventories, and any exchange receivable (representing amounts of natural gas inventories used by the other parties to the agreement but not yet replenished for which UGI Utilities has the rights), are included in the caption "Gas Utility natural gas" in the table above.

As of June 30, 2015, UGI Utilities has SCAAs with Energy Services and a non-affiliate. The carrying value of gas storage inventories released under the SCAAs with non-affiliates at June 30, 2015, September 30, 2014 and June 30, 2014, comprising 1.9 billion cubic feet ("bcf"), 3.9 bcf and 2.1 bcf of natural gas, was $4.5, $16.8 and $8.9, respectively.

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Note 5 — Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	June 30, 2015	September 30, 2014	June 30, 2014
Goodwill (not subject to amortization)	$2,927.7	$2,833.4	$2,885.1
Intangible assets:			
Customer relationships, noncompete agreements and other	$761.9	$712.0	$717.3
Accumulated amortization	(268.4)	(263.8)	(259.0)
Intangible assets, net (definite-lived)	493.5	448.2	458.3
Trademarks and tradenames (indefinite-lived)	135.0	128.2	132.0
Total intangible assets, net	$628.5	$576.4	$590.3

The increase in goodwill and intangible assets at June 30, 2015, reflects the preliminary purchase price allocation of Totalgaz to these assets (see Note 15) partially offset by the effects of currency translation. Amortization expense of intangible assets was $13.1 and $38.1 for the three and nine months ended June 30, 2015, respectively. Amortization expense of intangible assets was $13.3 and $35.5 for the three and nine months ended June 30, 2014, respectively. Amortization expense included in cost of sales in the Condensed Consolidated Statements of Income is not material. The estimated aggregate amortization expense of intangible assets for the remainder of Fiscal 2015 and for the next four fiscal years is as follows: remainder of Fiscal 2015 — $13.7; Fiscal 2016 — $50.1; Fiscal 2017 — $43.9; Fiscal 2018 — $42.2; Fiscal 2019 — $40.6.

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Note 6 — Utility Regulatory Assets and Liabilities and Regulatory Matters

For a description of the Company’s regulatory assets and liabilities other than those described below, see Note 9 in the Company’s 2014 Annual Report. UGI Utilities does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with Utilities are included in our accompanying Condensed Consolidated Balance Sheets:

	June 30, 2015	September 30, 2014	June 30, 2014
Regulatory assets (a):			
Income taxes recoverable	$111.8	$110.7	$107.2
Underfunded pension and postretirement plans	103.2	110.1	89.2
Environmental costs	14.5	14.6	14.6
Deferred fuel and power costs	—	11.8	9.4
Removal costs, net	19.6	16.8	15.6
Other	5.1	4.2	6.6
Total regulatory assets	$254.2	$268.2	$242.6
Regulatory liabilities (a):			
Postretirement benefits	$19.6	$18.6	$17.5
Environmental overcollections	—	0.3	1.6
Deferred fuel and power refunds	45.6	0.3	—
State tax benefits—distribution system repairs	10.9	10.1	9.3
Other	1.4	3.2	1.9
Total regulatory liabilities	$77.5	$32.5	$30.3

(a) Noncurrent regulatory assets are recorded in other assets and regulatory liabilities are recorded in other current and other noncurrent liabilities in the Condensed Consolidated Balance Sheets.

Deferred fuel and power—costs and refunds. Gas Utility’s and Electric Utility’s tariffs contain clauses that permit recovery of all prudently incurred purchased gas and power costs through the application of purchased gas cost (“PGC”) rates in the case of Gas Utility and default service (“DS”) tariffs in the case of Electric Utility. The clauses provide for periodic adjustments to PGC and DS rates for differences between the total amount of purchased gas and electric generation supply costs collected from customers and recoverable costs incurred. Net undercollected costs are classified as a regulatory asset and net overcollections are classified as a regulatory liability.

Gas Utility uses derivative instruments to reduce volatility in the cost of gas it purchases for firm- residential, commercial and industrial (“retail core-market”) customers. Realized and unrealized gains or losses on natural gas derivative instruments are included in deferred fuel costs or refunds. Net unrealized gains (losses) on such contracts at June 30, 2015, September 30, 2014 and June 30, 2014 were $(0.7), $(1.4) and $0.7, respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Previous to March 1, 2015, we did not designate these purchase contracts as an NPNS election under GAAP. Therefore, we recognized the fair value of these contracts on the balance sheet with an associated adjustment to regulatory assets or liabilities because Electric Utility is entitled to fully recover its DS costs. At June 30, 2015, September 30, 2014, and June 30, 2014, the fair values of Electric Utility’s electricity supply contracts were gains (losses) of $(1.4), $0.3 and $0.8, respectively. These amounts are reflected in current and noncurrent derivative assets and current and noncurrent derivative liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power costs and refunds in the table above. Effective with Electric Utility forward electricity purchase contracts entered into beginning March 1, 2015, Electric Utility has elected the NPNS exception under GAAP and, as a result, the fair values of such contracts are not recognized on the balance sheet (see Note 12).

In order to reduce volatility associated with a substantial portion of its electric transmission congestion costs, Electric Utility obtains financial transmission rights ("FTRs"). FTRs are derivative instruments that entitle the holder to receive compensation for electricity transmission congestion charges when there is insufficient electricity transmission capacity on the electric transmission grid. Because Electric Utility is entitled to fully recover its DS costs, realized and unrealized gains or losses on FTRs are included in deferred fuel and power costs or deferred fuel and power refunds. Unrealized gains or losses on FTRs at June 30, 2015, September 30, 2014, and June 30, 2014, were not material.

Distribution System Improvement Charge. On April 14, 2012, legislation enabling gas and electric utilities in Pennsylvania to seek to charge recovery of eligible capital investment in distribution system infrastructure improvement projects became effective. The charge enabled by the legislation is known as a distribution system improvement charge ("DSIC"). The primary benefit to a company from a DSIC charge is the elimination of regulatory lag, or delayed rate recognition, that occurs under traditional ratemaking relating to qualifying capital expenditures, for up to five percent of distribution rates. To be eligible for a DSIC, a utility must have filed a general rate filing within five years of its petition seeking permission to include a DSIC in its tariff. PNG and CPG began seeking permission to include a DSIC in their tariffs in 2014, while UGI Gas has not had a general rate filing within the required time period to be eligible. Beginning on April 1, 2015, PNG was able to include a DSIC charge in its tariff rate in accordance with a PUC order. The impact of the DSIC charge at PNG did not have a material effect on Gas Utility results of operations.

Note 7 — Energy Services Accounts Receivable Securitization Facility

Energy Services has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2015. The Receivables Facility provides Energy Services with the ability to borrow up to $150 of eligible receivables during the period November to May and up to $75 of eligible receivables during the period June to October. Energy Services uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts, capital expenditures, dividends and for general corporate purposes.

Under the Receivables Facility, Energy Services transfers, on an ongoing basis and without recourse, its trade accounts receivable to its wholly owned, special purpose subsidiary, Energy Services Funding Corporation ("ESFC"), which is consolidated for financial statement purposes. ESFC, in turn, has sold and, subject to certain conditions, may from time to time sell, an undivided interest in some or all of the receivables to a major bank. ESFC was created and has been structured to isolate its assets from creditors of Energy Services and its affiliates, including UGI. Trade receivables sold to the bank remain on the Company's balance sheet and the Company reflects a liability equal to the amount advanced by the bank or the commercial paper conduit. The Company records interest expense on amounts owed to the bank or the commercial paper conduit. Energy Services continues to service, administer and collect trade receivables on behalf of the bank or commercial paper issuer, as applicable.

During the nine months ended June 30, 2015 and 2014, Energy Services transferred trade receivables to ESFC totaling $873.4 and $1,073.1, respectively. During the nine months ended June 30, 2015 and 2014, ESFC sold an aggregate $272.5 and $196.0, respectively, of undivided interests in its trade receivables to the bank. At June 30, 2015, the outstanding balance of ESFC receivables was $42.9 of which $20.0 was sold to the bank. At June 30, 2014, the outstanding balance of ESFC receivables was $57.7 and there were no amounts sold to the bank. Losses on sales of receivables to the bank during the nine months ended June 30, 2015 and 2014, which are included in interest expense on the Condensed Consolidated Statements of Income, were not material.

Note 8 — Debt

On March 27, 2015, UGI Utilities entered into an unsecured revolving credit agreement (the "UGI Utilities 2015 Credit Agreement") with a group of banks providing for borrowings up to $300 (including a $100 sublimit for letters of credit). Concurrently with entering into the UGI Utilities 2015 Credit Agreement, UGI Utilities terminated its then-existing $300 revolving credit agreement dated as of May 25, 2011. Under the UGI Utilities 2015 Credit Agreement, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The UGI Utilities 2015 Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.0. The UGI Utilities 2015 Credit Agreement is currently scheduled to expire in March 2016, but may be extended by UGI Utilities to March 2020 if on or before March 25, 2016, UGI Utilities receives approval for the UGI Utilities 2015 Credit Agreement by the PUC. UGI Utilities filed to obtain such approval on June 30, 2015.

On May 29, 2015, UGI France, an indirect wholly owned subsidiary of UGI, borrowed €600 ($659.6) under its Senior Facilities Agreement with a consortium of banks (the "2015 Senior Facilities Agreement"). UGI France entered into the 2015 Senior Facilities Agreement on April 30, 2015, in anticipation of its then-pending acquisition of Totalgaz, which was consummated on May 29, 2015 (see Note 15). The 2015 Senior Facilities Agreement consists of a €600 variable-rate term loan and a €60 revolving credit facility. The term loan proceeds were used (1) to fund a portion of the acquisition of Totalgaz, including related fees and expenses; (2) to make a capital contribution from UGI France to its wholly owned subsidiary, AGZ Holding, to prepay €342 principal amount, plus accrued interest, outstanding under Antargaz' 2011 Senior Facilities Agreement due March 2016 (the "2011 Senior Facilities Agreement"); (3) to settle Antargaz' existing pay-fixed, receive-variable interest rate swaps associated with the 2011 Senior Facilities Agreement; and (4) for general corporate purposes. As a result of prepaying the term loan outstanding under the 2011 Senior Facilities Agreement and concurrently settling the associated pay-fixed, receive-variable interest rate swaps, we recorded a pre-tax loss of $10.3 comprising a $9.0 loss on interest rate swaps and the write-off of $1.3 of debt issuance costs. These amounts are included in interest expense on the Condensed Consolidated Statements of Income.

Borrowings under the 2015 Senior Facilities Agreement €600 term loan and the €60 revolving credit facility bear interest at rates per annum comprising the aggregate of the applicable margin and the associated euribor rate, which euribor rate has a floor of 0.0%. The margin on such borrowings (which ranges from 1.60% to 2.70% for the term loan, and 1.45% to 2.55% for the revolving credit facility) are dependent upon the ratio of UGI France's consolidated total net debt to earnings before interest expense, income taxes, depreciation, and amortization ("EBITDA"), each as defined in the 2015 Senior Facilities Agreement. Through March 31, 2016, the margin has been set at 2.50%. UGI France has entered into pay-fixed, receive-variable interest rate swaps through April 30, 2019, to generally fix the underlying euribor rate at 0.18% (assuming such underlying euribor rate is not less than 0.0%). At June 30, 2015, the effective interest rate on the 2015 Senior Facilities Agreement term loan was 2.68%. At June 30, 2015, there were no borrowings under the revolving credit facility.

Principal amounts outstanding under the 2015 Senior Facilities Agreement term loan are due as follows: €60 due April 30, 2018; €60 due April 30, 2019; and €480 due April 30, 2020. The 2015 Senior Facilities Agreement restricts the ability of UGI France to, among other things, incur additional indebtedness, make investments, incur liens, and effect mergers, consolidations and sales of assets, and requires UGI France and its consolidated subsidiaries to maintain a ratio of total net debt to EBITDA, each as defined in the 2015 Senior Facilities Agreement, that shall not exceed (a) 3.75 to 1.00 from the closing date of the Totalgaz acquisition to September 30, 2015, and (b) 3.50 to 1.00 from October 1, 2015, to the final maturity date. UGI France will generally be permitted to make restricted payments, such as dividends, if no event of default exists or would exist upon payment of such dividend.

Note 9 — Commitments and Contingencies

Environmental Matters

UGI Utilities

CPG is party to a Consent Order and Agreement ("CPG-COA") with the Pennsylvania Department of Environmental Protection ("DEP") requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which manufactured gas plant ("MGP") related facilities were operated ("CPG MGP Properties") and to plug a minimum number of non-producing natural gas wells per year. In addition, PNG is a party to a Multi-Site Remediation Consent Order and Agreement ("PNG-COA") with the DEP. The PNG-COA requires PNG to perform annually a specified level of activities associated with environmental investigation and remediation work at certain properties on which MGP-related facilities were operated ("PNG MGP Properties"). Under these agreements, environmental expenditures relating to the CPG MGP Properties and the PNG MGP Properties are capped at $1.8 and $1.1, respectively, in any calendar year. The CPG-COA is scheduled to terminate at the end of 2018. The PNG-COA terminates in 2019 but may be terminated by either party effective at the end of any two-year period beginning with the original effective date in March 2004. At June 30, 2015 and 2014, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $9.6 and $11.4, respectively. We have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable.

From the late 1800s through the mid-1900s, UGI Utilities and its former subsidiaries owned and operated a number of MGPs prior to the general availability of natural gas. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under the Superfund Law and may be present on the sites of former MGPs. Between 1882 and 1953, UGI Utilities owned the stock of subsidiary gas companies in Pennsylvania and elsewhere and also operated the businesses of some gas companies under agreement. Pursuant to the requirements of the Public Utility Holding Company Act of 1935, by the early 1950s UGI Utilities divested all of its utility operations other than certain Pennsylvania operations, including those which now constitute UGI Gas and Electric Utility.

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UGI Utilities does not expect its costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because (1) UGI Gas is currently permitted to include in rates, through future base rate proceedings, a five-year average of such prudently incurred remediation costs, and (2) CPG and PNG are currently receiving regulatory recovery of estimated environmental investigation and remediation costs associated with Pennsylvania sites. At June 30, 2015, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material.

From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by its former subsidiaries. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by former subsidiaries of UGI Utilities if a court were to conclude that (1) the subsidiary's separate corporate form should be disregarded, or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary's MGP.

Other Matters

Purported Class Action Lawsuits. Between May and October of 2014, more than 35 purported class action lawsuits were filed in multiple jurisdictions against the Partnership/UGI Corporation and a competitor by certain of their direct and indirect customers. The class action lawsuits allege, among other things, that the Partnership and its competitor colluded, beginning in 2008, to reduce the fill level of portable propane cylinders from 17 pounds to 15 pounds and combined to persuade its common customer, Walmart Stores, Inc., to accept that fill reduction, resulting in increased cylinder costs to retailers and end-user customers in violation of federal and certain state antitrust laws. The claims seek treble damages, injunctive relief, attorneys' fees and costs on behalf of the putative classes. On October 16, 2014, the United States Judicial Panel on Multidistrict Litigation transferred all of these purported class action cases to the Western Division of the United States District Court for the Western District of Missouri. In July 2015, the Court dismissed all claims brought by direct customers and all claims other than those for injunctive relief brought by indirect customers. The direct customers have filed a notice of appeal with the United States Court of Appeals for the Eighth Circuit; other procedural responses may be available to the indirect customers. We are unable to reasonably estimate the impact, if any, arising from such litigation. We believe we have strong defenses to the claims and intend to vigorously defend against them.

In addition to the matters described above, there are other pending claims and legal actions arising in the normal course of our businesses. Although we cannot predict the final results of these pending claims and legal actions, we believe, after consultation with counsel, that the final outcome of these matters will not have a material effect on our consolidated financial position, results of operations or cash flows.

Note 10 — Defined Benefit Pension and Other Postretirement Plans

In the U.S., we sponsor a defined benefit pension plan for employees hired prior to January 1, 2009, of UGI, UGI Utilities, PNG, CPG and certain of UGI's other domestic wholly owned subsidiaries ("U.S. Pension Plan"). We also provide postretirement health care benefits to certain retirees and active employees and postretirement life insurance benefits to nearly all U.S. active and retired employees. In addition, Antargaz employees are covered by certain defined benefit pension and postretirement plans.

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Net periodic pension expense and other postretirement benefit costs include the following components:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2015	2014	2015	2014
Service cost	$2.5	$2.3	$0.2	$0.1
Interest cost	6.2	6.5	0.2	0.2
Expected return on assets	(7.9)	(7.3)	(0.2)	(0.1)
Amortization of:				
Prior service cost (benefit)	—	0.1	(0.2)	(0.1)
Actuarial loss	2.5	1.9	0.1	—
Net benefit cost	3.3	3.5	0.1	0.1
Change in associated regulatory liabilities	—	—	0.9	0.9
Net expense	$3.3	$3.5	$1.0	$1.0

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2015	2014	2015	2014
Service cost	$7.4	$7.0	$0.5	$0.4
Interest cost	18.8	19.4	0.6	0.7
Expected return on assets	(23.8)	(22.0)	(0.5)	(0.4)
Amortization of:				
Prior service cost (benefit)	0.2	0.2	(0.4)	(0.4)
Actuarial loss	7.5	5.7	0.1	0.1
Net benefit cost	10.1	10.3	0.3	0.4
Change in associated regulatory liabilities	—	—	2.8	2.7
Net expense	$10.1	$10.3	$3.1	$3.1

The U.S. Pension Plan's assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, smallcap common stocks and UGI Common Stock. It is our general policy to fund amounts for U.S. Pension Plan benefits equal to at least the minimum required contribution set forth in applicable employee benefit laws. During the nine months ended June 30, 2015 and 2014, the Company made cash contributions to the U.S. Pension Plan of $8.4 and $11.0, respectively. The Company expects to make additional discretionary cash contributions of approximately $2.8 to the U.S. Pension Plan during the remainder of Fiscal 2015.

UGI Utilities has established a Voluntary Employees' Beneficiary Association ("VEBA") trust to pay retiree health care and life insurance benefits by depositing into the VEBA the annual amount of postretirement benefits costs, if any, determined under GAAP. The difference between such amount and amounts included in UGI Gas' and Electric Utility's rates is deferred for future recovery from, or refund to, ratepayers. There were no required contributions to the VEBA during the nine months ended June 30, 2015 and 2014.

We also sponsor unfunded and non-qualified supplemental executive defined benefit retirement plans ("Supplemental Defined Benefit Plans"). We recorded pre-tax expense associated with these plans of $0.7 and $0.6 in the three months ended June 30, 2015 and 2014, respectively. We recorded pre-tax expense associated with these plans of $2.0 and $2.3 in the nine months ended June 30, 2015 and 2014, respectively.

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Note 11 — Fair Value Measurements

Recurring Fair Value Measurements

The following table presents on a gross basis our financial assets and liabilities including both current and noncurrent portions, that are measured at fair value on a recurring basis within the fair value hierarchy, as of June 30, 2015, September 30, 2014 and June 30, 2014:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
June 30, 2015:				
Derivative instruments:				
Assets:				
Commodity contracts	$13.6	$8.2	$—	$21.8
Foreign currency contracts	$—	$29.1	$—	$29.1
Interest rate contracts	$—	$1.0	$—	$1.0
Cross-currency swaps	$—	$8.2	$—	$8.2
Liabilities:				
Commodity contracts	$(58.6)	$(94.0)	$—	$(152.6)
Foreign currency contracts	$—	$(0.1)	$—	$(0.1)
Interest rate contracts	$—	$(2.0)	$—	$(2.0)
Non-qualified supplemental postretirement grantor trust investments (a)	$31.8	$—	$—	$31.8
September 30, 2014:				
Derivative instruments:				
Assets:				
Commodity contracts	$10.6	$19.8	$—	$30.4
Foreign currency contracts	$—	$12.8	$—	$12.8
Interest rate contracts	$—	$0.1	$—	$0.1
Cross-currency swaps	$—	$2.1	$—	$2.1
Liabilities:				
Commodity contracts	$(21.2)	$(32.9)	$—	$(54.1)
Foreign currency contracts	$—	$(0.1)	$—	$(0.1)
Interest rate contracts	$—	$(21.0)	$—	$(21.0)
Non-qualified supplemental postretirement grantor trust investments (a)	$30.0	$—	$—	$30.0
June 30, 2014 (b):				
Derivative instruments:				
Assets:				
Commodity contracts	$17.9	$15.1	$—	$33.0
Foreign currency contracts	$—	$0.8	$—	$0.8
Liabilities:				
Commodity contracts	$(15.6)	$(15.3)	$—	$(30.9)
Foreign currency contracts	$—	$(5.1)	$—	$(5.1)
Interest rate contracts	$—	$(25.2)	$—	$(25.2)
Cross-currency swaps	$—	$(2.0)	$—	$(2.0)

Non-qualified supplemental postretirement grantor trust investments (a)	$30.4	$—	$—	$30.4

(a) Consists primarily of mutual fund investments held in grantor trusts associated with non-qualified supplemental retirement plans.
(b) Certain immaterial amounts have been revised to correct the classification of derivatives.

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The fair values of our Level 1 exchange-traded commodity futures and option contracts and non-exchange-traded commodity futures and forward contracts are based upon actively quoted market prices for identical assets and liabilities. The remainder of our derivative instruments are designated as Level 2. The fair values of certain non-exchange traded commodity derivatives designated as Level 2 are based upon indicative price quotations available through brokers, industry price publications or recent market transactions and related market indicators. For commodity option contracts designated as Level 2 that are not traded on an exchange, we use a Black Scholes option pricing model that considers time value and volatility of the underlying commodity. The fair values of our Level 2 interest rate contracts and foreign currency contracts are based upon third-party quotes or indicative values based on recent market transactions. The fair values of investments held in grantor trusts are derived from quoted market prices as substantially all of the investments in these trusts have active markets. There were no transfers between Level 1 and Level 2 during the periods presented.

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. At June 30, 2015, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,711.6 and $3,887.0, respectively. At June 30, 2014, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,556.2 and $3,805.4, respectively. We estimate the fair value of long-term debt by using current market rates and by discounting future cash flows using rates available for similar type debt (Level 2).

Financial instruments other than derivative instruments, such as our short-term investments and trade accounts receivable, could expose us to concentrations of credit risk. We limit our credit risk from short-term investments by investing only in investment-grade commercial paper, money market mutual funds, securities guaranteed by the U.S. Government or its agencies and FDIC insured bank deposits. The credit risk arising from concentrations of trade accounts receivable is limited because we have a large customer base that extends across many different U.S. markets and a number of foreign countries. For information regarding concentrations of credit risk associated with our derivative instruments, see Note 12. Our investment in a private equity partnership is measured at fair value on a non-recurring basis. Generally this measurement uses Level 3 fair value inputs because the investment does not have a readily available market value.

Note 12 — Derivative Instruments and Hedging Activities

We are exposed to certain market risks related to our ongoing business operations. Management uses derivative financial and commodity instruments, among other things, to manage these risks. The primary risks managed by derivative instruments are (1) commodity price risk, (2) interest rate risk, and (3) foreign currency exchange rate risk. Although we use derivative financial and commodity instruments to reduce market risk associated with forecasted transactions, we do not use derivative financial and commodity instruments for speculative or trading purposes. The use of derivative instruments is controlled by our risk management and credit policies, which govern, among other things, the derivative instruments we can use, counterparty credit limits and contract authorization limits.

Commodity Price Risk

In order to manage market price risk associated with the Partnership's fixed-price programs, the Partnership uses over-the-counter derivative commodity instruments, principally price swap contracts. In addition, the Partnership, certain other domestic business units and our UGI International operations also use over-the-counter price swap and option contracts to reduce commodity price volatility associated with a portion of their forecasted LPG purchases. The Partnership from time to time enters into price swap and put option agreements to reduce the effects of short-term commodity price volatility. At June 30, 2015 and 2014, total volumes associated with LPG commodity derivative instruments totaled 405.9 million gallons and 274.3 million gallons, respectively. At June 30, 2015, the maximum period over which we are economically hedging our exposure to LPG commodity price risk is 42 months.

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to retail core-market customers, including the cost of financial instruments used to hedge purchased gas costs. As permitted and agreed to by the PUC pursuant to Gas Utility's annual PGC filings, Gas Utility currently uses New York Mercantile Exchange ("NYMEX") natural gas futures and option contracts to reduce commodity price volatility associated with a portion of the natural gas it purchases for its retail core-market customers. At June 30, 2015 and 2014, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.1 million dekatherms and 10.9 million dekatherms, respectively. At June 30, 2015, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 15 months. Gains and losses on natural gas futures contracts and any gains on natural gas option contracts are recorded in regulatory assets or liabilities on the Condensed Consolidated Balance Sheets because it is probable such gains or losses will be recoverable from, or refundable to, customers through the PGC recovery mechanism (see Note 6).

Electric Utility's DS tariffs permit the recovery of all prudently incurred costs of electricity it sells to DS customers, including the cost of financial instruments used to hedge electricity costs. Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. For such contracts entered into by Electric Utility prior to March 1, 2015, Electric Utility chose not to elect the NPNS exception under GAAP related to these derivative instruments and the fair values of these contracts are reflected in current and noncurrent derivative instrument assets and liabilities in the accompanying Condensed Consolidated Balance Sheets. Associated gains and losses on these forward contracts are recorded in regulatory assets and liabilities on the Condensed Consolidated Balance Sheets in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 6). Effective with Electric Utility forward electricity purchase contracts entered into beginning March 1, 2015, Electric Utility has elected the NPNS exception under GAAP and, as a result, the fair values of such contracts are not recognized on the balance sheet. At June 30, 2015 and 2014, the volumes of Electric Utility's forward electricity purchase contracts were 494.5 million kilowatt hours and 315.8 million kilowatt hours, respectively. At June 30, 2015, the maximum period over which these contracts extend is 11 months.

In order to reduce volatility associated with a substantial portion of its electricity transmission congestion costs, Electric Utility obtains FTRs through an annual allocation process. Midstream & Marketing purchases FTRs to economically hedge electricity transmission congestion costs associated with its fixed-price electricity sales contracts and from time to time also enters into New York Independent System Operator ("NYISO") capacity swap contracts to economically hedge the locational basis differences for customers it serves on the NYISO electricity grid. Gains and losses on Electric Utility FTRs are recorded in regulatory assets or liabilities in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 6). At June 30, 2015 and 2014, the total volumes associated with FTRs and NYISO capacity contracts totaled 494.5 million kilowatt hours and 747.4 million kilowatt hours, respectively. At June 30, 2015, the maximum period over which we are economically hedging electricity congestion and locational basis differences is 11 months.
In order to manage market price risk relating to fixed-price sales contracts for natural gas and electricity, Midstream & Marketing enters into NYMEX and over-the-counter natural gas futures contracts, Intercontinental Exchange ("ICE") natural gas basis swap contracts, and electricity futures contracts. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to hedge the price of a portion of its anticipated future sales of electricity from its electric generation facilities. In addition, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later near-term sale of natural gas or propane. Because it could no longer assert the NPNS exception under GAAP for new contracts entered into for the forward purchase of natural gas and pipeline transportation, beginning in the second quarter of Fiscal 2014 Energy Services began recording these contracts at fair value with changes in fair value reflected in cost of sales.

At June 30, 2015 and 2014, total volumes associated with Midstream & Marketing's natural gas futures, forward and pipeline contracts totaled 57.2 million dekatherms and 67.7 million dekatherms, respectively. At June 30, 2015, the maximum period over which we are hedging our exposure to the variability in cash flows associated with natural gas commodity price risk is 45 months. At June 30, 2015 and 2014, total volumes associated with Midstream & Marketing’s electricity call contracts and electricity put contracts totaled 429.5 million kilowatt hours and 210.5 million kilowatt hours, and 492.5 million kilowatt hours and 193.2 million kilowatt hours, respectively. At June 30, 2015, the maximum period over which we are hedging our exposure to the variability in cash flows associated with electricity commodity price risk (excluding Electric Utility) is 30 months for electricity call contracts and 15 months for electricity put contracts. At June 30, 2015, the volumes associated with Midstream & Marketing’s natural gas storage and propane storage NYMEX contracts totaled 0.8 million dekatherms and 2.0 million gallons, respectively. At June 30, 2014, the volumes associated with Midstream & Marketing’s natural gas storage and propane storage NYMEX contracts totaled 0.5 million dekatherms and 2.9 million gallons, respectively.

At June 30, 2015, the amount of net gains associated with commodity derivative instruments previously designated and qualified as cash flow hedges expected to be reclassified into earnings during the next twelve months is not material.

Interest Rate Risk

Antargaz' and Flaga's long-term debt agreements have interest rates that are generally indexed to short-term market interest rates. Antargaz and Flaga have each entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on their variable-rate term loans through the respective scheduled maturity dates. As of June 30, 2015 and 2014, the total notional amounts of variable-rate debt subject to interest rate swap agreements (excluding Flaga's cross-currency swap as described below) were €659.1 and €401.1, respectively.

Our domestic businesses' long-term debt is typically issued at fixed rates of interest. As these long-term debt issues mature, we typically refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce market rate risk on the underlying benchmark rate of interest associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs"). At June 30, 2015 and 2014, we had no unsettled IRPAs.

We account for interest rate swaps and IRPAs as cash flow hedges. At June 30, 2015, the amount of net losses associated with interest rate hedges (excluding pay-fixed, receive-variable interest rate swaps) expected to be reclassified into earnings during the next twelve months is $2.6.

Foreign Currency Exchange Rate Risk

In order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases during the heating-season months of October through March through the use of forward foreign currency exchange contracts. At June 30, 2015 and 2014, we were hedging a total of $227.9 and $219.8 of U.S. dollar-denominated LPG purchases, respectively. At June 30, 2015, the maximum period over which we are hedging our exposure to the variability in cash flows associated with U.S. dollar-denominated purchases of LPG is 33 months. From time to time we also enter into forward foreign currency exchange contracts to reduce the volatility of the U.S. dollar value on a portion of our International Propane euro-denominated net investments. At June 30, 2015 and 2014, we had no euro-denominated net investment hedges.

We account for foreign currency exchange contracts associated with anticipated purchases of U.S. dollar-denominated LPG as cash flow hedges. At June 30, 2015, the amount of net gains associated with currency rate risk (other than net investment hedges) expected to be reclassified into earnings during the next twelve months based upon current fair values is $16.1.

Cross-Currency Swaps

During Fiscal 2013, Flaga entered into a cross-currency swap to hedge its exposure to the variability in expected future cash flows associated with foreign currency and interest rate risk resulting from the issuance of $52 of U.S. dollar-denominated variable-rate debt. The cross-currency hedge includes initial and final exchanges of principal from a fixed euro denomination to a fixed U.S. dollar-denominated amount, to be exchanged at a specified rate, which was determined by the market spot rate on the date of issuance. The cross-currency swap also includes an interest rate swap of a fixed foreign-denominated interest rate to a fixed U.S. dollar-denominated interest rate. We have designated this cross-currency swap as a cash flow hedge. At June 30, 2015, the amount of net gains associated with this cross-currency swap expected to be reclassified into earnings over the next twelve months is not material.

Derivative Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative instrument counterparties. Our derivative instrument counterparties principally comprise large energy companies and major U.S. and international financial institutions. We maintain credit policies with regard to our counterparties that we believe reduce overall credit risk. These policies include evaluating and monitoring our counterparties' financial condition, including their credit ratings, and entering into agreements with counterparties that govern credit limits or entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. Certain of these agreements call for the posting of collateral by the counterparty or by the Company in the form of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2015 and 2014, restricted cash in brokerage accounts totaled $45.2 and $5.9, respectively. Although we have concentrations of credit risk associated with derivative instruments, the maximum amount of loss, based upon the gross fair values of the derivative instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at June 30, 2015. Certain of the Partnership's derivative contracts have credit-risk-related contingent features that may require the posting of additional collateral in the event of a downgrade of the Partnership's debt rating. At June 30, 2015, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

Fair Value of Derivative Instruments

The following table presents the Company's derivative assets and liabilities on a gross basis as of June 30, 2015 and 2014:

	June 30, 2015	June 30, 2014 (a)
Derivative assets:		
Derivatives designated as hedging instruments:		
Commodity contracts	$—	$8.1
Foreign currency contracts	29.1	0.8
Cross-currency contracts	8.2	—
Interest rate contracts	1.0	—
	38.3	8.9
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	1.9	2.4
Derivatives not designated as hedging instruments:		
Commodity contracts	19.9	22.5
Total derivative assets	$60.1	$33.8
Derivative liabilities:		
Derivatives designated as hedging instruments:		
Commodity contracts	$—	$(4.2)
Foreign currency contracts	(0.1)	(5.1)
Cross-currency contracts	—	(2.0)
Interest rate contracts	(2.0)	(25.2)
	(2.1)	(36.5)
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	(4.8)	(0.8)
Derivatives not designated as hedging instruments:		
Commodity contracts	(147.8)	(25.9)
Total derivative liabilities	$(154.7)	$(63.2)

(a) Certain immaterial amounts have been revised to correct the classification of derivatives.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on our Condensed Consolidated Balance Sheets if the right of offset exists. Our derivative instruments include both those that are executed on an exchange through brokers and centrally cleared and over-the-counter transactions. Exchange contracts utilize a financial intermediary, exchange or clearinghouse to enter, execute or clear the transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter and exchange contracts contain contractual rights of offset through master netting arrangements, derivative clearing agreements and contract default provisions. In addition, the contracts are subject to conditional rights of offset through counterparty nonperformance, insolvency or other conditions.

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In general, most of our over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral generally include cash or letters of credit. Cash collateral paid by us to our over-the-counter derivative counterparties, if any, is reflected in the table below to offset derivative liabilities. Cash collateral received by us from our over-the-counter derivative counterparties, if any, is reflected in the table below to offset derivative assets. Certain other accounts receivable and accounts payable balances recognized on our Condensed Consolidated Balance Sheets with our derivative counterparties are not included in the table below but could reduce our net exposure to such counterparties because such balances are subject to master netting or similar arrangements.

The following table presents the Company’s derivative assets and liabilities, as well as the effects of offsetting, as of June 30, 2015 and 2014:

	Gross Amounts Recognized	Gross Amounts Offset in Balance Sheet	Net Amounts Recognized	Cash Collateral (Received) Pledged	Net Amounts Recognized in Balance Sheet
June 30, 2015					
Derivative assets	$60.1	$(17.2)	$42.9	$—	$42.9
Derivative liabilities	$(154.7)	$17.2	$(137.5)	$2.2	$(135.3)
June 30, 2014					
Derivative assets	$33.8	$(20.1)	$13.7	$—	$13.7
Derivative liabilities	$(63.2)	$20.1	$(43.1)	$—	$(43.1)

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Effect of Derivative Instruments

The following tables provide information on the effects of derivative instruments in the Condensed Consolidated Statements of Income and changes in AOCI and noncontrolling interests for the three and nine months ended June 30, 2015 and 2014:

	Gain (Loss) Recognized in AOCI and Noncontrolling Interests		Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income		Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Three Months Ended June 30,	2015	2014	2015	2014	
Cash Flow Hedges:					
Commodity contracts	$—	$(1.7)	$0.1	$4.3	Cost of sales
Foreign currency contracts	(6.4)	1.1	0.4	(0.2)	Cost of sales
Cross-currency contracts	(1.5)	—	8.6	(0.1)	Interest expense/other operating income, net
Interest rate contracts	0.6	(0.6)	(11.5)	(3.9)	Interest expense
Total	$(7.3)	$(1.2)	$(2.4)	$0.1	

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Three Months Ended June 30,	2015	2014	
Derivatives Not Designated as Hedging Instruments:			
Commodity contracts	$(23.5)	$(4.9)	Cost of sales
Commodity contracts	0.3	—	Revenues
Commodity contracts	0.1	—	Operating expenses / other operating income, net
Total	$(23.1)	$(4.9)	

	Gain (Loss) Recognized in AOCI and Noncontrolling Interests		Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income		Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Nine Months Ended June 30,	2015	2014	2015	2014	
Cash Flow Hedges:					
Commodity contracts	$—	$59.5	$(2.2)	$66.5	Cost of sales
Foreign currency contracts	26.0	(1.6)	9.6	(3.7)	Cost of sales
Cross-currency contracts	6.0	(1.1)	8.5	(0.2)	Interest expense/other operating income, net
Interest rate contracts	3.0	(4.1)	(18.9)	(12.0)	Interest expense
Total	$35.0	$52.7	$(3.0)	$50.6	

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Nine Months Ended June 30,	2015	2014	

Derivatives Not Designated as Hedging Instruments:			
Commodity contracts	$(328.3)	$(14.3)	Cost of sales
Commodity contracts	(0.5)	—	Revenues
Commodity contracts	(0.4)	0.1	Operating expenses/other operating income, net
Total	$(329.2)	$(14.2)	

The amounts of derivative gains or losses representing ineffectiveness, and the amounts of gains or losses recognized in income as a result of excluding derivatives from ineffectiveness testing, were not material for the three and nine months ended June 30, 2015 and 2014.

In May 2015, the Company prepaid term loans outstanding under Antargaz' 2011 Senior Facilities Agreement. In conjunction with the prepayment, the Company also settled its associated pay-fixed, receive-variable interest rate swaps, and discontinued cash flow hedge accounting treatment for such swaps. During the three months ended June 30, 2015, the Company recorded a pre-tax loss of $9.0 associated with the discontinuance of cash flow hedge accounting for the swaps, which amount is included in interest expense on the Condensed Consolidated Statements of Income (see Note 8).

We are also a party to a number of other contracts that have elements of a derivative instrument. These contracts include, among others, binding purchase orders, contracts that provide for the purchase and delivery, or sale, of energy products, and service contracts that require the counterparty to provide commodity storage, transportation or capacity service to meet our normal sales commitments. Although many of these contracts have the requisite elements of a derivative instrument, certain of these contracts qualify for NPNS exception accounting under GAAP because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold.

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Note 13 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI during the three and nine months ended June 30, 2015 and 2014:

Three Months Ended June 30, 2015	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency (a)	Total
AOCI - March 31, 2015	$(19.6)	$20.5	$(86.3)	$(85.4)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	(4.8)	(23.0)	(27.8)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.5	2.4	—	2.9
Reclassification adjustments tax expense	(0.1)	(1.9)	—	(2.0)
Reclassification adjustments (after-tax)	0.4	0.5	—	0.9
Other comprehensive income (loss)	0.4	(4.3)	(23.0)	(26.9)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	0.1	—	0.1
Other comprehensive income (loss) attributable to UGI	0.4	(4.2)	(23.0)	(26.8)
AOCI - June 30, 2015	$(19.2)	$16.3	$(109.3)	$(112.2)

Three Months Ended June 30, 2014	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI - March 31, 2014	$(15.8)	$(23.3)	$63.4	$24.3
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	(0.6)	(0.2)	(0.8)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.4	(0.2)	—	0.2
Reclassification adjustments tax benefit	(0.2)	(1.3)	—	(1.5)
Reclassification adjustments (after-tax)	0.2	(1.5)	—	(1.3)
Other comprehensive income (loss)	0.2	(2.1)	(0.2)	(2.1)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	3.2	—	3.2
Other comprehensive income (loss) attributable to UGI	0.2	1.1	(0.2)	1.1
AOCI - June 30, 2014	$(15.6)	$(22.2)	$63.2	$25.4

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Nine Months Ended June 30, 2015	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency (a)	Total
AOCI - September 30, 2014	$(20.6)	$(9.3)	$8.7	$(21.2)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	23.1	(118.0)	(94.9)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	2.1	3.0	—	5.1
Reclassification adjustments tax expense	(0.7)	(2.3)	—	(3.0)
Reclassification adjustments (after-tax)	1.4	0.7	—	2.1
Other comprehensive income (loss)	1.4	23.8	(118.0)	(92.8)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	1.8	—	1.8
Other comprehensive income (loss) attributable to UGI	1.4	25.6	(118.0)	(91.0)
AOCI - June 30, 2015	$(19.2)	$16.3	$(109.3)	$(112.2)

Nine Months Ended June 30, 2014	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI - September 30, 2013	$(16.4)	$(26.9)	$51.7	$8.4
Other comprehensive income before reclassification adjustments (after-tax)	—	46.2	11.5	57.7
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	1.0	(50.7)	—	(49.7)
Reclassification adjustments tax benefit	(0.2)	4.0	—	3.8
Reclassification adjustments (after-tax)	0.8	(46.7)	—	(45.9)
Other comprehensive income	0.8	(0.5)	11.5	11.8
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	5.2	—	5.2
Other comprehensive income attributable to UGI	0.8	4.7	11.5	17.0
AOCI - June 30, 2014	$(15.6)	$(22.2)	$63.2	$25.4

(a) See Note 2 relating to correction of prior period error in comprehensive income.

For additional information on amounts reclassified from AOCI relating to derivative instruments, see Note 12.

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Note 14 — Segment Information

Our operations comprise six reportable segments generally based upon products sold, geographic location and regulatory environment. Our reportable segments comprise: (1) AmeriGas Propane; (2) an international LPG segment comprising Antargaz; (3) an international LPG segment principally comprising Flaga and AvantiGas; (4) Gas Utility; (5) Energy Services; and (6) Electric Generation. We refer to both international segments together as "UGI International" and Energy Services and Electric Generation together as "Midstream & Marketing." Finagaz is included in our Antargaz reportable segment in the table below from the date of its acquisition on May 29, 2015.

The accounting policies of our reportable segments are the same as those described in Note 2, "Summary of Significant Accounting Policies," in the Company's 2014 Annual Report. We evaluate AmeriGas Propane's performance principally based upon the Partnership's earnings before interest expense, income taxes, depreciation and amortization as adjusted for net gains and losses on commodity derivative instruments not associated with current-period transactions ("Partnership Adjusted EBITDA"). Although we use Partnership Adjusted EBITDA to evaluate AmeriGas Propane's profitability, it should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not a measure of performance or financial condition under GAAP. Our definition of Partnership Adjusted EBITDA may be different from that used by other companies. We evaluate the performance of our other reportable segments principally based upon their income before income taxes as adjusted for gains and losses on commodity derivative instruments not associated with current-period transactions. Net gains and losses on commodity derivative instruments not associated with current-period transactions are reflected in Corporate & Other because the Company's chief operating decision maker does not consider such items when evaluating the financial performance of our reportable segments.

					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Three Months Ended June 30, 2015									
Revenues	$1,148.1	$(27.0)(c)	$478.0	$119.4	$169.7	$ 16.2	$196.1	$150.7	$45.0
Cost of sales	$586.4	$(26.4)(c)	$211.4	$41.3	$135.9	$ 7.7	$107.9	$101.8	$6.8
Segment profit:									
Operating income (loss)	$56.1	$—	$0.8	$15.1	$17.3	$ 1.3	$(9.1)	$8.8	$21.9
Loss from equity investees	—	—	—	—	—	—	—	—	—
Interest expense	(67.5)	—	(40.3)	(9.5)	(0.5)	—	(15.7)(d)	(0.9)	(0.6)
(Loss) income before income taxes	$(11.4)	$—	$(39.5)	$5.6	$16.8	$ 1.3	$(24.8)	$7.9	$21.3
Partnership Adjusted EBITDA (a)			$48.9						
Noncontrolling interests' net income	$(25.5)	$—	$(36.1)	$—	$—	$ —	$(0.2)	$—	$10.8

(loss)									
Depreciation and amortization	$92.5	$0.1	$48.0	$14.8	$3.7	$ 3.2	$15.2	$5.9	$ 1.6
Capital expenditures	$113.2	$—	$20.7	$41.3	$27.5	$ 1.1	$17.2	$3.3	$ 2.1

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					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Three Months Ended June 30, 2014									
Revenues	$1,486.7	$(50.8)(c)	$613.2	$128.3	$248.3	$ 20.5	$249.2	$232.3	$45.7
Cost of sales	$926.5	$(49.6)(c)	$340.8	$49.2	$209.2	$ 10.5	$164.1	$180.7	$21.6
Segment profit:									
Operating income (loss)	$62.7	$(0.1)	$7.2	$17.1	$23.5	$ 2.6	$(1.4)	$8.2	$5.6
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(60.1)	—	(41.4)	(9.8)	(0.5)	—	(6.3)	(1.4)	(0.7)
Income (loss) before income taxes	$2.5	$(0.1)	$(34.2)	$7.3	$23.0	$ 2.6	$(7.8)	$6.8	$4.9
Partnership Adjusted EBITDA (a)			$55.1						
Noncontrolling interests' net loss	$(33.3)	$—	$(31.0)	$—	$—	$ —	$(0.3)	$—	$(2.0)
Depreciation and amortization	$90.0	$—	$47.8	$13.7	$3.3	$ 2.7	$14.6	$6.2	$1.7
Capital expenditures	$102.4	$1.2	$29.3	$35.9	$11.2	$ 1.9	$15.6	$4.8	$2.5

					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Nine Months Ended June 30, 2015									
Revenues	$5,608.3	$(209.4)(c)	$2,467.1	$847.9	$876.1	$57.5	$881.2	$548.2	$139.7
Cost of sales	$3,196.4	$(207.4)(c)	$1,179.0	$426.7	$666.8	$25.1	$517.5	$397.7	$191.0
Segment profit:									
Operating income (loss)	$841.5	$0.1	$437.4	$226.2	$157.4	$8.6	$82.5	$35.4	$(106.1)
Loss from equity investees	(1.1)	—	—	—	—	—	(1.1)	—	—
Interest expense	(184.7)	—	(122.4)	(29.7)	(1.6)	—	(26.2)(d)	(2.8)	(2.0)
Income (loss) before income taxes	$655.7	$0.1	$315.0	$196.5	$155.8	$8.6	$55.2	$32.6	$(108.1)
			$579.5						

Partnership Adjusted EBITDA (a)									
Noncontrolling interests' net income	$176.3	$—	$211.6	$—	$—	$—	$0.2	$—	$(35.5)
Depreciation and amortization	$271.5	$—	$145.5	$43.6	$10.9	$9.2	$40.3	$17.2	$4.8
Capital expenditures	$328.1	$—	$77.9	$134.0	$46.2	$10.0	$38.9	$15.1	$6.0
As of June 30, 2015									
Total assets	$10,520.0	$(121.8)	$4,202.6	$2,279.0	$629.9	$277.6	$2,377.9	$534.5	$340.3
Short-term borrowings	$68.0	$—	$43.6	$2.7	$20.0	$—	$—	$1.7	$—
Goodwill	$2,927.7	$—	$1,954.1	$182.1	$5.6	$—	$699.8	$79.8	$6.3

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(unaudited)
(Millions of dollars and euros, except per share amounts)

	Total	Eliminations	AmeriGas Propane	Gas Utility	Midstream & Marketing Energy Services	Midstream & Marketing Electric Generation	UGI International Antargaz	UGI International Flaga & Other	Corporate & Other (b)
Nine Months Ended June 30, 2014									
Revenues	$6,965.9	$(281.0) (c)	$3,152.7	$880.0	$1,109.9	$66.4	$1,086.5	$802.8	$148.6
Cost of sales	$4,357.7	$(278.0) (c)	$1,809.0	$463.5	$894.2	$30.5	$713.3	$635.1	$90.1
Segment profit:									
Operating income (loss)	$1,015.0	$—	$471.7	$233.7	$166.8	$16.9	$94.7	$32.8	$(1.6)
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(178.9)	—	(125.0)	(26.6)	(2.5)	—	(19.1)	(3.8)	(1.9)
Income (loss) before income taxes	$836.0	$—	$346.7	$207.1	$164.3	$16.9	$75.5	$29.0	$(3.5)
Partnership EBITDA (a)			$616.5						
Noncontrolling interests' net income (loss)	$235.6	$—	$237.6	$—	$—	$—	$—	$—	$(2.0)
Depreciation and amortization	$271.7	$(0.1)	$149.3	$40.7	$9.1	$8.0	$39.9	$20.0	$4.8
Capital expenditures	$290.5	$—	$80.3	$98.8	$41.3	$13.0	$36.7	$13.6	$6.8
As of June 30, 2014									
Total assets	$10,077.7	$(112.8)	$4,345.8	$2,147.4	$542.7	$279.1	$1,784.2	$650.6	$440.7
Short-term borrowings	$96.5	$—	$92.5	$—	$—	$—	$—	$4.0	$—
Goodwill	$2,885.1	$—	$1,939.0	$182.1	$5.6	$—	$651.7	$99.7	$7.0

(a) The following table provides a reconciliation of Partnership Adjusted EBITDA to AmeriGas Propane operating income:

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Nine Months Ended June 30, 2015	Nine Months Ended June 30, 2014
Partnership Adjusted EBITDA	$48.9	$55.1	$579.5	$616.5
Depreciation and amortization	(48.0)	(47.8)	(145.5)	(149.3)
Noncontrolling interests (i)	(0.1)	(0.1)	3.4	4.5
Operating income	$0.8	$7.2	$437.4	$471.7

(i) Principally represents the General Partner's 1.01% interest in AmeriGas OLP.

(b) Corporate & Other results principally comprise (1) Electric Utility, (2) Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses ("HVAC"), (3) net expenses of UGI's captive general liability insurance company, and (4) UGI Corporation's unallocated corporate and general expenses and interest income. In addition, Corporate & Other results also include net gains and (losses) on commodity derivative instruments not associated with current-period transactions totaling $18.1 and $4.2 during the three months ended June 30, 2015 and 2014, respectively, and $(109.4) and $(1.8) during the nine months ended June 30, 2015 and 2014, respectively. Corporate & Other assets principally comprise cash, short-term investments, the assets of Electric Utility and HVAC. Through March 2014, Corporate and Other also had an intercompany loan. The intercompany loan interest is removed in the segment presentation.

(c) Represents the elimination of intersegment transactions principally among Midstream & Marketing, Gas Utility and AmeriGas Propane.

(d) Antargaz interest expense includes pre-tax loss of $10.3 associated with an early extinguishment of debt (see Note 8).

Note 15 — Acquisition of Totalgaz

On May 29, 2015 (the "Acquisition Date"), UGI, through its wholly owned indirect subsidiary, UGI France, completed the acquisition of all of the outstanding shares of Totalgaz, a retail distributor of LPG in France, for €453.0 ($497.8) in cash (the "Totalgaz Acquisition"), including €30.0 ($33.0) for estimated Acquisition Date working capital. The Acquisition Date cash consideration is subject to adjustment primarily based upon the final Acquisition Date working capital. The Totalgaz Acquisition was consummated pursuant to the terms of a Share Purchase Agreement dated November 11, 2014, between Total Marketing

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Services, a subsidiary of global energy company Total, and UGI France. The Totalgaz Acquisition nearly doubles UGI's retail LPG distribution business in France and is consistent with our growth strategies, one of which is to grow our core business through acquisitions. The Totalgaz Acquisition was funded from existing cash balances and a portion of loan proceeds from UGI France's May 29, 2015, issuance of a €600 term loan under its 2015 Senior Facilities Agreement (see Note 8). From and after the Acquisition Date, the Totalgaz business is referred to herein as Finagaz.

The Company has accounted for the Totalgaz Acquisition using the acquisition method. The preliminary allocation of the purchase price is based upon estimates of the fair values of the assets acquired and liabilities assumed, using information currently available. The Company expects to obtain additional information during the measurement period under GAAP of up to one year from the Acquisition Date as necessary to determine the final allocation of the purchase price to the assets acquired and liabilities assumed, including tax assets and liabilities and related tax attributes. Accordingly, the fair value estimates presented below are subject to change. The components of the preliminary purchase price allocation are as follows:

Assets acquired:	
Cash	$86.8
Accounts receivable (a)	170.3
Prepaid expenses and other current assets	11.7
Property, plant and equipment	375.3
Intangible assets (b)	98.0
Other assets	30.9
Total assets acquired	$773.0
Liabilities assumed:	
Accounts payable	109.2
Other current liabilities	103.4
Deferred income taxes	120.3
Other noncurrent liabilities	109.4
Total liabilities assumed	$442.3
Goodwill	167.1
Net consideration transferred	$497.8

(a) Approximates the gross contractual amounts of receivables acquired.
(b) Represents $86.0 of customer relationships and $12.0 of tradenames, which have preliminary average amortization periods of approximately 15 years.

The excess of the purchase price for Totalgaz over the preliminary fair values of the assets acquired and liabilities assumed has been reflected as goodwill, assigned to the Antargaz reportable segment, and results principally from anticipated synergies and value creation resulting from the Company's combined LPG businesses in France. The goodwill is not deductible for income tax purposes.
The Company recognized $2.7 and $13.7 of direct transaction-related costs associated with the Totalgaz Acquisition during the three and nine months ended June 30, 2015, respectively, which costs are reflected in operating and administrative expenses on the Condensed Consolidated Statements of Income.

Revenues and net income of Finagaz from the Acquisition Date through June 30, 2015 were not material to UGI's consolidated results of operations.

The following table presents unaudited pro forma revenues, net income attributable to UGI Corporation and earnings per share data for the three and nine months ended June 30, 2015 and 2014 as if the Totalgaz Acquisition had occurred on October 1, 2013. The pro forma net income also reflects the effects of the issuance of the €600 term loan under the 2015 Senior Facilities Agreement and the associated repayment of the term loan outstanding under the 2011 Senior Facilities Agreement as if such transactions had occurred on October 1, 2013. Amounts in the table below exclude the loss associated with the early extinguishment of debt under the 2011 Senior Facilities Agreement (see Note 8):

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$1,204.2	$1,611.6	$5,983.0	$7,512.9
Net income attributable to UGI Corporation	$16.3	$17.6	$348.5	$397.3
Earnings per common share attributable to UGI Corporation shareholders:				
Basic	$0.09	$0.10	$2.01	$2.30
Diluted	$0.09	$0.10	$1.98	$2.27

The unaudited pro forma consolidated information reflects Totalgaz' historical results after giving effect to adjustments directly attributable to the transaction, including depreciation, amortization, interest expense, intercompany eliminations and related income tax effects. The unaudited pro forma consolidated information is not necessarily indicative of the results that would have occurred had the Totalgaz Acquisition occurred on the date indicated nor are they necessarily indicative of future operating results.

In connection with the Totalgaz Acquisition, the Company agreed with the French Competition Authority (the "FCA") to divest certain assets and investments of Totalgaz and Antargaz no later than 15 months subsequent to the Acquisition Date. Following the closing of the Totalgaz Acquisition, two competitors in the French LPG distribution market challenged the decision of the FCA. The competitors' request for interim measures suspending the effectiveness of the agreed remedies was denied by the supreme administrative court (conseil d'etat). Proceedings on the merits are continuing. While UGI cannot predict the final outcome of these proceedings at this time, we believe the FCA and the Company have strong defenses to the claims and intend to vigorously defend against them.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

Information contained in this Quarterly Report on Form 10-Q may contain 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 (the "Exchange Act"). Such statements use forward-looking words such as "believe," "plan," "anticipate," "continue," "estimate," "expect," "may," or other similar words. These statements discuss plans, strategies, events or developments that we expect or anticipate will or may occur in the future.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, we caution you that actual results almost always vary from assumed facts or bases, and the differences between actual results and assumed facts or bases can be material, depending on the circumstances. When considering forward-looking statements, you should keep in mind the following important factors that could affect our future results and could cause those results to differ materially from those expressed in our forward-looking statements: (1) adverse weather conditions resulting in reduced demand; (2) cost volatility and availability of propane and other liquefied petroleum gases, oil, electricity, and natural gas and the capacity to transport product to our customers; (3) changes in domestic and foreign laws and regulations, including safety, tax, consumer protection and accounting matters; (4) inability to timely recover costs through utility rate proceedings; (5) the impact of pending and future legal proceedings; (6) competitive pressures from the same and alternative energy sources; (7) failure to acquire new customers and retain current customers thereby reducing or limiting any increase in revenues; (8) liability for environmental claims; (9) increased customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand; (10) adverse labor relations; (11) large customer, counterparty or supplier defaults; (12) liability in excess of insurance coverage for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to generating and distributing electricity and transporting, storing and distributing natural gas and liquefied petroleum gases ("LPG"); (13) political, regulatory and economic conditions in the United States and in foreign countries, including the current conflicts in the Middle East and those involving Russia, and foreign currency exchange rate fluctuations, particularly the euro; (14) capital market conditions, including reduced access to capital markets and interest rate fluctuations; (15) changes in commodity market prices resulting in significantly higher cash collateral requirements; (16) reduced distributions from subsidiaries; (17) changes in Marcellus Shale gas production; (18) the timing and success of our acquisitions, commercial initiatives and investments to grow our businesses; and (19) our ability to successfully integrate acquired businesses and achieve anticipated synergies.

These factors, and those factors set forth in Item 1A. Risk Factors in the Company's 2014 Annual Report, are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other unknown or unpredictable factors could also have material adverse effects on future results. We undertake no obligation to update publicly any forward-looking statement whether as a result of new information or future events except as required by the federal securities laws.

ANALYSIS OF RESULTS OF OPERATIONS

The following analyses compare the Company's results of operations for the three months ended June 30, 2015 ("2015 three-month period") with the three months ended June 30, 2014 ("2014 three-month period") and the nine months ended June 30, 2015 ("2015 nine-month period") with the nine months ended June 30, 2014 ("2014 nine-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 14 to the condensed consolidated financial statements. Because most of our businesses sell or distribute energy products used in large part for heating purposes, our results are significantly influenced by temperatures in our service territories, particularly during the heating season months of October through March. As a result, our earnings, excluding the effects of gains and losses on commodity derivative instruments not associated with current period transactions as further discussed below, are significantly higher in our first and second fiscal quarters.

Volatility in net income attributable to UGI as determined in accordance with accounting principles generally accepted in the U.S. (“GAAP”) can occur as a result of gains and losses on commodity derivative instruments not associated with current period transactions. These gains and losses result principally from recording changes in unrealized gains and losses on unsettled commodity derivative instruments and, to a much lesser extent, certain realized gains and losses on settled commodity derivative instruments that are not associated with current-period transactions. As further described below under the caption, “Non-GAAP Financial Measures - Adjusted Net Income Attributable to UGI and Adjusted Earnings Per Diluted Share,” UGI management uses “adjusted net income attributable to UGI” and “adjusted diluted earnings per share,” both of which are non-GAAP financial measures, when evaluating UGI’s overall performance. Adjusted net income attributable to UGI is net income attributable to UGI after excluding net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions and items that management regards as highly unusual and not expected to recur.

On May 29, 2015 (the “Acquisition Date”), UGI, through its wholly owned indirect subsidiary, UGI France, completed the acquisition of all of the outstanding shares of Totalgaz, a retail distributor of LPG in France, for €453.0 million ($497.8 million) in cash (the “Totalgaz Acquisition”), including €30.0 million ($33.0 million) for estimated Acquisition Date working capital. The Totalgaz Acquisition nearly doubles UGI’s retail LPG distribution business in France and is consistent with our growth strategies, one of which is to grow our core business through acquisitions. From and after the Acquisition Date, Totalgaz business is referred to herein as Finagaz.

Executive Overview

Three Months Ended June 30, 2015 Results

We recorded GAAP net income attributable to UGI Corporation for the 2015 three-month period of $9.6 million, equal to $0.05 per diluted share, compared to GAAP net income attributable to UGI Corporation for the 2014 three-month period of $20.6 million, equal to $0.12 per diluted share. GAAP net income attributable to UGI during the 2015 and 2014 three-month periods include after-tax gains on commodity derivative instruments not associated with current-period transactions totaling $4.9 million (equal to $0.02 per diluted share) and $3.5 million (equal to $0.02 per diluted share), respectively. These net after-tax gains on commodity derivative instruments are included in “Corporate & Other” in our business unit summary table below.

Adjusted net income attributable to UGI was $4.7 million (equal to $0.03 per diluted share) in the 2015 three-month period compared to $17.1 million (equal to $0.10 per diluted share) in the 2014 three-month period. The $12.4 million decrease in adjusted net income attributable to UGI in the 2015 three-month period includes a loss on an early extinguishment of debt at Antargaz, which increased interest expense and decreased pre-tax income by $10.3 million ($4.6 million after-tax), and also reflects the effects of the Totalgaz Acquisition, including a seasonal loss subsequent to its acquisition and approximately $5.3 million of pre-tax acquisition and transition-related expenses ($3.3 million after-tax). Adjusted net income from Midstream & Marketing was $3.1 million lower in the 2015 three-month period principally due to lower capacity management total margin as the prior-year three-month period experienced greater volatility in capacity values between Marcellus and non-Marcellus delivery points. Our Gas Utility and AmeriGas Propane segments experienced weather that was substantially warmer than in the prior-year three-month period which reduced sales volumes and associated total margin.

The euro and the British pound sterling were significantly weaker during the 2015 three-month period compared to the prior-year period. The difference in euro-to-U.S. dollar translation rates and, to a lesser extent, the difference in the British pound sterling-to-U.S. dollar translation rates, did not have a material impact on UGI International net loss for the 2015 three-month period.

Nine Months Ended June 30, 2015 Results

We recorded GAAP net income attributable to UGI Corporation for the 2015 nine-month period of $290.2 million, equal to $1.65 per diluted share, compared to GAAP net income attributable to UGI Corporation for the 2014 nine-month period of $357.0 million, equal to $2.04 per diluted share. The $66.8 million decrease in GAAP net income attributable to UGI during the 2015 nine-month period reflects after-tax losses on commodity derivative instruments not associated with current-period transactions totaling $(46.2) million (equal to $(0.27) per diluted share). Such net after-tax gains and losses in the 2014 nine-month period were not material. The $(46.2) million of after-tax losses on commodity derivative instruments not associated with current-period transactions recorded in the 2015 nine-month period reflect the effects of substantial declines in worldwide energy commodity prices. GAAP net income attributable to UGI in the 2014 nine-month period also reflects the retroactive effect to Fiscal 2013 of a change in tax laws in France, which increased 2014 nine-month period tax expense, and reduced 2014 nine-month period GAAP net income attributable to UGI, by $5.7 million or $0.03 per diluted share.

Adjusted net income attributable to UGI was $336.4 million (equal to $1.92 per diluted share) in the 2015 nine-month period compared to $362.7 million (equal to $2.07 per diluted share) in the 2014 nine-month period. The $26.3 million decrease in adjusted net income attributable to UGI in the 2015 nine-month period includes a $12.5 million decrease in adjusted net income at UGI International (excluding the effects in the 2014 nine-month period of the $5.7 million French tax law adjustment retroactive to Fiscal 2013); a $10.3 million decrease in adjusted net income from Midstream & Marketing; a $4.4 million decrease in adjusted net income attributable to UGI from AmeriGas Propane; and a $4.1 million decrease in net income from our Gas Utility. Our UGI International results in the 2015 nine-month period include the previously mentioned pre-tax loss of $10.3 million ($4.6 million after-tax) from the early extinguishment of debt. UGI International results also include the effects of the Totalgaz Acquisition, including a seasonal loss subsequent to its acquisition, and approximately $16.3 million of pre-tax acquisition and transition-related expenses ($10.9 million after-tax). UGI International average temperatures during the 2015 nine-month period were warmer than normal but slightly colder than the prior-year nine-month period. The decrease in adjusted Midstream & Marketing results principally reflects slightly lower total margin and higher operating and depreciation expenses due in part to the expansion of our midstream assets. Midstream & Marketing continues to benefit from the growing demand for natural gas in the Northeast and Mid-Atlantic regions and the infrastructure gap that exists in bringing Marcellus Shale gas to markets in these regions. The lower AmeriGas Propane results principally reflect the effects on volumes sold from weather that was warmer than normal and warmer than in the prior-year nine-month period. Gas Utility results in the 2015 nine-month period were lower, notwithstanding a slight increase in total margin, reflecting higher operating and administrative expenses.

Although the euro and the British pound sterling were significantly weaker during the 2015 nine-month period, the effects of these weaker currencies on UGI International net income were offset in large part by gains on foreign currency exchange contracts.

We believe each of our business units has sufficient liquidity in the form of revolving credit facilities and, with respect to Energy Services, also an accounts receivable securitization facility, to fund business operations during Fiscal 2015 (see “Financial Condition and Liquidity” below).

Non-GAAP Financial Measures - Adjusted Net Income Attributable to UGI and Adjusted Earnings Per Diluted Share

As previously mentioned, UGI management uses “adjusted net income attributable to UGI” and “adjusted diluted earnings per share,” both of which are non-GAAP financial measures, when evaluating UGI’s overall performance. Adjusted net income attributable to UGI is net income attributable to UGI after excluding net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions, principally comprising changes in unrealized gains and losses on commodity derivative instruments, and items that management regards as highly unusual and not expected to recur.

Midstream & Marketing did not apply cash flow hedge accounting for its commodity derivative instruments during any of the periods presented. Effective October 1, 2014, UGI International determined that on a prospective basis it would not elect cash flow hedge accounting for its commodity derivative transactions and also de-designated its then-existing commodity derivative instruments accounted for as cash flow hedges. Also effective October 1, 2014, AmeriGas Propane de-designated its remaining commodity derivative instruments accounted for as cash flow hedges. Previously, AmeriGas Propane had discontinued cash flow hedge accounting for all commodity derivative instruments entered into beginning April 1, 2014. Realized and unrealized gains and losses on commodity derivative instruments are generally recorded in cost of sales or revenues.

Non-GAAP financial measures are not in accordance with, or an alternative to, GAAP and should be considered in addition to, and not as a substitute for, the comparable GAAP measures. Management believes that these non-GAAP measures provide meaningful information to investors about UGI’s performance because they eliminate the impact of (1) gains and losses on commodity derivative instruments not associated with current-period transactions and (2) those items that management regards as highly unusual in nature and not expected to recur.

The following table reconciles consolidated net income attributable to UGI Corporation, the most directly comparable GAAP measure, to adjusted net income attributable to UGI Corporation, and reconciles diluted earnings per share, the most comparable GAAP measure, to adjusted diluted earnings per share, to reflect the adjustments referred to above:

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(Millions of dollars, except per share amounts)	Three Months Ended June 30, 2015	2014	Nine Months Ended June 30, 2015	2014
Adjusted net income attributable to UGI Corporation:				
Net income attributable to UGI Corporation	$9.6	$20.6	$290.2	$357.0
Net after-tax (gains) losses on commodity derivative instruments not associated with current period transactions (a)	(4.9)	(3.5)	46.2	—
Retroactive impact of change in French tax law	—	—	—	5.7
Adjusted net income attributable to UGI Corporation	$4.7	$17.1	$336.4	$362.7
Adjusted diluted earnings per share:				
UGI Corporation earnings per share - diluted	$0.05	$0.12	$1.65	$2.04
Net after-tax (gains) losses on commodity derivative instruments not associated with current period transactions (b)	(0.02)	(0.02)	0.27	—
Retroactive impact of change in French tax law	—	—	—	0.03
Adjusted diluted earnings per share	$0.03	$0.10	$1.92	$2.07

(a) Income taxes associated with pre-tax adjustments determined using statutory business unit tax rates.
(b) Includes the effects of rounding.

RESULTS OF OPERATIONS

2015 three-month period compared to the 2014 three-month period

Net Income Attributable to UGI Corporation by Business Unit

For the three months ended June 30,	2015		2014		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane	$(2.4)	(25.0)%	$(1.8)	(8.7)%	$(0.6)	(33.3)%
UGI International (a)	(9.9)	(103.1)%	0.4	1.9%	(10.3)	N.M
Gas Utility	4.5	46.9%	5.7	27.7%	(1.2)	(21.1)%
Midstream & Marketing	11.0	114.6%	14.1	68.4%	(3.1)	(22.0)%
Corporate & Other (b)	6.4	66.6%	2.2	10.7%	4.2	N.M.
Net income attributable to UGI Corporation	$9.6	100.0%	$20.6	100.0%	$(11.0)	(53.4)%

(a) Three months ended June 30, 2015, includes an after-tax loss of $(4.6) million associated with an early extinguishment of debt at Antargaz.
(b) Includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $4.9 million and $3.5 million for the three months ended June 30, 2015 and 2014, respectively.
N.M. — Variance is not meaningful.

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AmeriGas Propane			
For the three months ended June 30,	2015	2014	Decrease	
(Dollars in millions)				
Revenues	$478.0	$613.2	$(135.2)	(22.0)%
Total margin (a)	$266.6	$272.4	$(5.8)	(2.1)%
Operating and administrative expenses	$223.3	$225.1	$(1.8)	(0.8)%
Partnership Adjusted EBITDA (b)	$48.9	$55.1	$(6.2)	(11.3)%
Operating income (b)	$0.8	$7.2	$(6.4)	(88.9)%
Retail gallons sold (millions)	202.2	215.6	(13.4)	(6.2)%
Degree days—% (warmer) than normal (c)	(18.5)%	(9.3)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin excludes net pre-tax gains (losses) of $14.8 million and $(2.8) million on AmeriGas Propane commodity derivative instruments not associated with current-period transactions during the three months ended June 30, 2015 and 2014, respectively.

(b) Partnership Adjusted EBITDA (earnings before interest expense, income taxes and depreciation and amortization as adjusted for net gains and losses on commodity derivative instruments not associated with current-period transactions) should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 14 to condensed consolidated financial statements).

(c) Deviation from average heating degree days for the 30-year period 1971-2000 based upon national weather statistics provided by the National Oceanic and Atmospheric Administration ("NOAA") for 335 airports in the United States, excluding Alaska.

AmeriGas Propane's retail gallons sold during the 2015 three-month period decreased 6.2% compared with the prior-year period. The decline in retail gallons sold in the 2015 three-month period principally reflects average temperatures based upon heating degree days that were 18.5% warmer than normal and 10.2% warmer than the prior-year three-month period.

Retail propane revenues decreased $130.1 million during the 2015 three-month period reflecting lower average retail selling prices ($96.7 million), principally the result of the significantly lower propane product costs and, to a much lesser extent, the effects of the lower retail volumes sold ($33.4 million). Wholesale propane revenues decreased $5.7 million during the 2015 three-month period reflecting the effects of lower wholesale selling prices ($7.1 million) partially offset by the effects of slightly higher wholesale volumes sold ($1.4 million). Average daily wholesale propane commodity prices during the 2015 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 55% lower than such prices during the 2014 three-month period. Revenues from fee income and other ancillary sales and services in the 2015 three-month period were slightly higher than in the prior-year period. Total cost of sales during the 2015 three-month period decreased $129.4 million, to $211.4 million, principally reflecting the effects of the lower average propane product costs ($112.8 million) and the lower retail and wholesale volumes sold ($17.6 million) on propane cost of sales.

Total margin decreased $5.8 million in the 2015 three-month period principally reflecting lower retail propane total margin ($5.7 million). The decrease in retail propane total margin largely reflects the previously mentioned decline in retail gallons sold partially offset by the impact of slightly higher average retail propane unit margin.

Partnership Adjusted EBITDA in the 2015 three-month period decreased $6.2 million principally reflecting the lower total margin ($5.8 million) and lower other operating income partially offset by lower operating and administrative expenses ($1.8 million). The decrease in operating and administrative expenses principally resulted from lower vehicle fuel expenses and lower uncollectible accounts expense. Operating income decreased $6.4 million in the 2015 three-month period principally reflecting the $6.2 million decrease in Partnership Adjusted EBITDA.

UGI International

For the three months ended June 30,	2015	2014	Increase (Decrease)	
(Dollars in millions)				
Revenues	$346.8	$481.5	$(134.7)	(28.0)%
Total margin (a)	$137.1	$136.7	$0.4	0.3%
Operating and administrative expenses	$117.0	$112.5	$4.5	4.0%
Operating (loss) income	$(0.3)	$6.8	$(7.1)	(104.4)%
Loss before income taxes	$(16.9)	$(1.0)	$(15.9)	N.M.
Retail gallons sold (millions) (b)	151.5	130.2	21.3	16.4%
Antargaz degree days—% (warmer) than normal (c)	(23.7)%	(19.8)%	—	—
Flaga degree days—% (warmer) than normal (c)	(2.0)%	(15.5)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended June 30, 2015 excludes net pre-tax gains of $1.1 million on UGI International's commodity derivative instruments not associated with current-period transactions.
(b) Excludes retail gallons from operations in China.
(c) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our Antargaz and Flaga service territories.
N.M. — Variance is not meaningful.

UGI International results include the results of Finagaz beginning May 29, 2015. Based upon heating degree day data, temperatures during the 2015 three-month period were significantly warmer than normal and slightly warmer than the prior-year period in France, while temperatures at Flaga and AvantiGas were near normal but colder than the 2014 three-month period. Total retail gallons sold during the 2015 three-month period were higher principally reflecting incremental retail LPG gallons associated with Finagaz for the period subsequent to its acquisition and, to lesser extent, the effects of colder spring 2015 three-month period weather on heating-related sales at Flaga and AvantiGas. During the 2015 three-month period, average wholesale commodity prices for both propane and butane in northwest Europe were approximately 40% lower than in the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during the reporting periods. The functional currency of a significant portion of our UGI International results is the euro. During the 2015 and 2014 three-month periods, the average un-weighted euro-to-dollar translation rates were approximately $1.11 and $1.37, respectively. Although the euro, and to a lesser extent the British pound sterling, were weaker during the 2015 three-month period, the differences in translation rates did not have a material impact on UGI International net loss for the 2015 three-month period.

UGI International revenues decreased $134.7 million during the 2015 three-month period principally reflecting the effects on revenues of the significantly weaker euro and the British pound sterling ($77.5 million) and the effects of lower average LPG sales prices at each of our European LPG businesses. The lower average LPG sales prices reflect the previously mentioned significant decline in LPG commodity prices. These decreases in revenues were partially offset by the effects of the higher retail LPG volumes sold. UGI International cost of sales decreased $135.1 million during the 2015 three-month period principally reflecting the effects of the lower average LPG wholesale prices and the effects of the significantly weaker euro and the British pound sterling ($46.2 million) partially offset by the greater retail LPG volumes sold.

Total UGI International margin increased $0.4 million compared to the prior-year three-month period as higher local currency gross margin at each of our European business units was offset, in large part, by the effects of the significantly weaker euro and the British pound sterling. Antargaz local currency total margin during the 2015 three-month period increased €18 million largely reflecting incremental margin from Finagaz subsequent to its acquisition.

UGI International operating income decreased $7.1 million from the prior-year three-month period. The decrease in operating income reflects the $0.4 million increase in total margin more than offset by a $4.5 million increase in operating and administrative expenses and lower other operating income. The increase in operating and administrative expenses reflects the effects of higher UGI International local currency operating and administrative expenses, principally incremental Finagaz expenses subsequent to its acquisition, and acquisition and transition-related expenses ($5.3 million). These higher local currency expenses were partially offset by the effects of the weaker euro. UGI International loss before income taxes increased $15.9 million principally reflecting the previously mentioned $7.1 million decrease in operating income and an increase in interest expense reflecting a $10.3 million pre-tax loss from an early extinguishment of debt at Antargaz (see Note 8 to condensed consolidated financial statements). UGI International interest expense during the three months ended June 30, 2015, excluding the $10.3 million loss from the early extinguishment of debt, declined $1.4 million reflecting the effects of the weaker euro and slightly lower local currency interest expense.

Gas Utility

For the three months ended June 30,	2015	2014	Increase (Decrease)	
(Dollars in millions)				
Revenues	$119.4	$128.3	$(8.9)	(6.9)%
Total margin (a)	$78.1	$79.1	$(1.0)	(1.3)%
Operating and administrative expenses	$48.6	$47.0	$1.6	3.4%
Operating income	$15.1	$17.1	$(2.0)	(11.7)%
Income before income taxes	$5.6	$7.3	$(1.7)	(23.3)%
System throughput—billions of cubic feet (“bcf”) —				
Core market	8.9	9.2	(0.3)	(3.3)%
Total	38.6	37.5	1.1	2.9%
Degree days—% (warmer) than normal (b)	(22.2)%	(6.3)%	—	—

(a) Total margin represents total revenues less total cost of sales.
(b) Deviation from average heating degree days for the 15-year period 1995-2009 based upon weather statistics provided by NOAA for airports located within Gas Utility’s service territory.

Temperatures in Gas Utility’s service territory in the 2015 three-month period based upon heating degree days were 22.2% warmer than normal and 17.0% warmer than the 2014 three-month period. Notwithstanding the warmer temperatures, total distribution system throughput increased 1.1 bcf (2.9%) principally reflecting higher delivery service volumes partially offset by slightly lower core market volumes. The lower core market volumes reflect the effects of the warmer spring weather partially offset by the benefits of a 1.7% increase in the number of core market customers. Gas Utility’s core market customers comprise firm- residential, commercial and industrial (“retail core-market”) customers who purchase their gas from Gas Utility and, to a much lesser extent, residential and small commercial customers who purchase their gas from alternate suppliers.

Gas Utility revenues decreased $8.9 million during the 2015 three-month period principally reflecting lower revenues from core market customers ($5.3 million). The decrease in core market revenues principally reflects the effects of the lower core market throughput and slightly lower average PGC rates during the 2015 three-month period. Increases or decreases in retail core-market revenues and cost of sales principally result from changes in retail core-market volumes and the level of gas costs collected through the PGC recovery mechanism. Under the PGC recovery mechanism, Gas Utility records the cost of gas associated with sales to retail core-market customers at amounts included in PGC rates. The difference between actual gas costs and the amounts included in rates is deferred on the balance sheet as a regulatory asset or liability and represents amounts to be collected from or refunded to customers in a future period. As a result of this PGC recovery mechanism, increases or decreases in the cost of gas associated with retail core-market customers have no direct effect on retail core-market margin. Gas Utility’s cost of sales was $41.3 million in the 2015 three-month period compared with $49.2 million in the 2014 three-month period principally reflecting the effects of the lower average PGC rates ($4.1 million) and lower retail core-market volumes sold ($1.2 million).

Gas Utility 2015 three-month period total margin decreased $1.0 million principally reflecting lower margin from interruptible delivery service customers and the effects of the slightly lower core market throughput.

Gas Utility operating income and income before income taxes during the 2015 three-month period decreased $2.0 million and $1.7 million, respectively, compared with the prior-year period. The decrease in Gas Utility operating income and income before income taxes during the 2015 three-month period principally reflects the decrease in total margin ($1.0 million), higher depreciation expense ($1.1 million) and slightly higher operating and administrative expenses ($1.6 million) partially offset by an increase in other operating income ($1.7 million). The increase in operating and administrative expenses includes, among other things, higher distribution system maintenance expenses and general and administrative expenses. The higher other operating income includes incremental margin from construction services.

Midstream & Marketing

For the three months ended June 30,	2015	2014	Increase (Decrease)	
(Dollars in millions)				
Revenues (a)	$183.3	$265.7	$(82.4)	(31.0)%
Total margin (b)	$42.3	$49.1	$(6.8)	(13.8)%
Operating and administrative expenses	$17.0	$16.9	$0.1	0.6%
Operating income	$18.6	$26.1	$(7.5)	(28.7)%
Income before income taxes	$18.1	$25.6	$(7.5)	(29.3)%

(a) Amounts are net of intercompany revenues between Midstream & Marketing's Energy Services and Electric Generation segments.

(b) Total margin represents total revenues less total cost of sales. Amounts exclude pre-tax gains from changes in the fair values of Midstream & Marketing's unsettled commodity derivative instruments and certain settled commodity derivative instruments not associated with current period transactions of $2.2 million and $7.0 million during the 2015 three-month period and the 2014 three-month period, respectively.

Midstream & Marketing 2015 three-month period total revenues were $82.4 million lower than the 2014 three-month period principally reflecting lower natural gas ($62.1 million), retail power ($8.7 million) and capacity management ($7.7 million) revenues. The decrease in natural gas revenues reflects lower wholesale and retail natural gas prices during the 2015 three-month period. The lower retail power revenues principally reflect the effects of lower volumes sold and, to a much lesser extent, lower average retail selling prices for electricity while the decline in capacity management revenues reflects lower average prices for capacity in the current-year period as the prior-year period experienced higher locational basis differences due to greater volatility in capacity values between Marcellus and non-Marcellus delivery points. Midstream & Marketing cost of sales decreased to $141.0 million in the 2015 three-month period compared to $216.6 million in the 2014 three-month period principally reflecting lower natural gas cost of sales ($63.9 million) on lower natural gas prices and lower cost of sales associated with the decline in retail power sales in the 2015 three-month period ($9.9 million).

Midstream & Marketing total margin decreased $6.8 million in the 2015 three-month period principally reflecting lower capacity management total margin ($7.7 million). The lower capacity management margin in the 2015 three-month period principally reflects lower average year-over-year prices for pipeline capacity as the prior-year period experienced higher locational basis differences due to greater volatility in capacity values between Marcellus and non-Marcellus delivery points. Electric Generation total margin declined $1.5 million principally due to lower electricity capacity revenue. These decreases in margin were partially offset by slightly higher natural gas and higher retail power total margin reflecting higher retail power unit margins.

Midstream & Marketing operating income and income before income taxes during the 2015 three-month period each decreased $7.5 million principally reflecting the previously mentioned decrease in total margin ($6.8 million). Operating and administrative expenses were about equal to the prior year as slightly higher compensation and benefits expenses were offset by lower business development and uncollectible accounts expenses and lower taxes other than income taxes. Depreciation expense was slightly higher in the 2015 three-month period principally reflecting incremental depreciation expense associated with Electric Generation's Conemaugh electricity generating unit.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2015 three-month period was $67.5 million, $7.4 million higher than the $60.1 million of interest expense recorded during the 2014 three-month period. Interest expense in the 2015 three-month period includes a $10.3 million pre-tax loss principally resulting from the early settlement of interest rate swaps associated with an extinguishment of debt at Antargaz. Excluding the pre-tax loss resulting from the early extinguishment of debt at Antargaz, total interest expense decreased $2.9 million reflecting in large part the effects on UGI International interest expense of the weaker euro and slightly lower local currency long-term debt interest expense. Our effective income tax rate as a percentage of pre-tax loss (excluding the effects on such rate of pre-tax income associated with noncontrolling interests not subject to federal income taxes) for the 2015 three-month period was lower than in the prior-year period. The lower percentage reflects in part the effect of a slight increase in the consolidated annual estimated effective tax rate.

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2015 nine-month period compared to the 2014 nine-month period

Net Income Attributable to UGI Corporation by Business Unit

For the nine months ended June 30,	2015		2014		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane	$62.0	21.4 %	$66.4	18.6 %	$(4.4)	(6.6)%
UGI International (a)	59.8	20.6 %	66.6	18.7 %	(6.8)	(10.2)%
Gas Utility	119.4	41.1 %	123.5	34.6 %	(4.1)	(3.3)%
Midstream & Marketing	97.6	33.6 %	107.9	30.2 %	(10.3)	(9.5)%
Corporate & Other (b)	(48.6)	(16.7)%	(7.4)	(2.1)%	(41.2)	N.M.
Net income attributable to UGI Corporation	$290.2	100.0 %	$357.0	100.0 %	$(66.8)	(18.7)%

(a) Nine months ended June 30, 2015, includes a net after-tax loss of $4.6 million associated with an early extinguishment of debt at Antargaz. Nine months ended June 30, 2014 includes income tax expense of $5.7 million to reflect the retroactive effects of a change in tax laws in France.

(b) Includes net after-tax (losses) on commodity derivative instruments not associated with current-period transactions of $(46.2) million for the nine months ended June 30, 2015. After-tax gains and losses in the 2014 nine-month period were not material.

N.M. — Variance is not meaningful.

AmeriGas Propane

For the nine months ended June 30,	2015	2014	Decrease	
(Dollars in millions)				
Revenues	$2,467.1	$3,152.7	$(685.6)	(21.7)%
Total margin (a)	$1,288.1	$1,343.7	$(55.6)	(4.1)%
Operating and administrative expenses	$728.1	$744.1	$(16.0)	(2.2)%
Partnership Adjusted EBITDA (b)	$579.5	$616.5	$(37.0)	(6.0)%
Operating income	$437.4	$471.7	$(34.3)	(7.3)%
Retail gallons sold (millions)	990.4	1,064.6	(74.2)	(7.0)%
Degree days—% (warmer) colder than normal (c)	(4.5)%	4.3 %	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the nine months ended June 30, 2015 and 2014 excludes net pre-tax (losses) of $(48.7) million and $(2.8) million, respectively, on AmeriGas Propane commodity derivative instruments not associated with current-period transactions.

(b) Partnership Adjusted EBITDA should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 14 to condensed consolidated financial statements).

(c) Deviation from average heating degree days for the 30-year period 1971-2000 based upon national weather statistics provided by NOAA for 335 airports in the United States, excluding Alaska.

AmeriGas Propane’s retail gallons sold during the 2015 nine-month period decreased 7.0% compared with the prior-year period. The decline in retail gallons sold in the 2015 nine-month period principally reflects average temperatures based upon heating degree days that were 4.5% warmer than normal and 8.4% warmer than the prior-year period.

Retail propane revenues decreased $ 601.6 million during the 2015 nine-month period reflecting lower average retail selling prices ($405.0 million), principally the result of the lower propane product costs, and the effects of lower retail volumes sold ($196.6 million). Wholesale propane revenues decreased $85.1 million during the 2015 nine-month period reflecting the effects of lower wholesale volumes sold ($59.4 million) and lower wholesale selling prices ($25.7 million). Average daily wholesale propane commodity prices during the 2015 nine-month period at Mont Belvieu, Texas were approximately 50% lower than such prices during the 2014 nine-month period. Revenues from fee income and other ancillary sales and services in the 2015 nine-month period were slightly higher than in the prior-year period. Total cost of sales during the 2015 nine-month period decreased $630.0

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million principally reflecting the effects of the significantly lower average propane product costs ($462.4 million) and the effects of the lower retail and wholesale volumes sold ($170.9 million) on propane cost of sales.

Total margin decreased $55.6 million in the 2015 nine-month period principally reflecting lower retail propane total margin ($50.5 million) and, to a much lesser extent, lower margin from wholesale sales and ancillary sales and services. The decrease in retail propane total margin largely reflects the previously mentioned decline in retail gallons sold partially offset by higher average propane retail unit margin.

Partnership Adjusted EBITDA in the 2015 nine-month period decreased $37.0 million principally reflecting the lower total margin ($55.6 million) offset in part by lower operating and administrative expenses ($16.0 million) and higher other operating income resulting, in large part, from sales of excess assets. The decrease in operating and administrative expenses reflects, among other things, lower vehicle expenses ($13.6 million), principally reflecting lower vehicle fuel expenses, and lower uncollectible accounts expense ($9.5 million) partially offset by, among other things, higher self-insured casualty and liability expenses. Operating income decreased $34.3 million in the 2015 nine-month period principally reflecting the lower Partnership Adjusted EBITDA ($37.0 million) partially offset by lower depreciation expense.

UGI International For the nine months ended June 30, (Dollars in millions)	2015	2014	Increase (Decrease)	
Revenues	$1,429.4	$1,889.3	$(459.9)	(24.3)%
Total margin (a)	$514.2	$540.9	$(26.7)	(4.9)%
Operating and administrative expenses	$343.1	$359.7	$(16.6)	(4.6)%
Operating income	$117.9	$127.5	$(9.6)	(7.5)%
Income before income taxes	$87.8	$104.5	$(16.7)	(16.0)%
Retail gallons sold (millions) (b)	521.8	499.4	22.4	4.5%
Antargaz degree days—% (warmer) than normal (c)	(11.6)%	(13.7)%	—	—
Flaga degree days—% (warmer) than normal (c)	(12.1)%	(15.7)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the nine months ended June 30, 2015 excludes net pre-tax (losses) of $(18.0) million on UGI International's commodity derivative instruments not associated with current-period transactions.
(b) Excludes retail gallons from operations in China.
(c) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our Antargaz and Flaga service territories.

UGI International results include the results of Finagaz subsequent to its acquisition on May 29, 2015. Based upon heating degree day data, temperatures during the 2015 nine-month period in our UGI International European LPG territories were significantly warmer than normal but slightly colder than in the 2014 nine-month period. Total retail gallons sold during the 2015 nine-month period were slightly higher than the prior-year nine-month period. During the 2015 nine-month period, average wholesale commodity prices for propane and butane in northwest Europe were each approximately 40% lower than in the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during the reporting periods. The functional currency of a significant portion of our UGI International results is the euro. During the 2015 nine-month period and the 2014 nine-month period, the average un-weighted euro-to-U.S. dollar translation rates were approximately $1.16 and $1.37, respectively. The difference in euro-to-U.S. dollar translation rates and, to a lesser extent, the difference in British pound sterling-to-U.S. dollar translation rates, reduced UGI

International net income but the decrease was largely offset by gains from foreign currency exchange contracts during the 2015 nine-month period.

UGI International revenues decreased $459.9 million during the 2015 nine-month period principally reflecting the combined impact on revenues of the significantly weaker euro and the British pound sterling ($226.1 million) and the effects of lower average LPG sales prices at each of our European LPG businesses. The lower average LPG sales prices reflect the previously mentioned significant decline in commodity LPG prices. These decreases in revenues were partially offset by the effects on revenues from the slightly higher retail LPG volumes sold and higher revenues from increased natural gas marketing volumes at Antargaz. UGI International cost of sales decreased $433.2 million during the 2015 nine-month period principally reflecting the lower average LPG wholesale prices during the 2015 nine-month period and the effects of the significantly weaker euro and the British pound

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sterling ($141.2 million) partially offset by the revenue effects from the higher UGI International retail LPG volumes sold and increased natural gas marketing volumes at Antargaz.

Total UGI International margin decreased $26.7 million compared to the prior-year nine-month period as a greater than 10% increase in local currency gross margin was more than offset by the effects of the significantly weaker euro and the British pound sterling. The increase in local currency gross margin reflects (1) higher local currency retail LPG total margin at Antargaz and AvantiGas principally resulting from the higher retail sales volumes, including margin from Finagaz subsequent to its acquisition, and higher retail LPG unit margins; (2) higher local currency natural gas total margin at Antargaz; and (3) greater income from foreign currency exchange contracts ($12.9 million). The increase in local currency total margin at Antargaz and AvantiGas were partially offset by lower total LPG margin at Flaga reflecting lower retail unit margins.

UGI International operating income decreased $9.6 million from the prior-year nine-month period. The decrease in operating income reflects the $26.7 million decrease in total margin partially offset by a $16.6 million decrease in operating and administrative expenses. The decrease in operating and administrative expenses reflects the effects of the weaker euro and British pound sterling partially offset by the effects of higher UGI International local currency operating and administrative expenses. The increase in UGI International local currency operating and administrative expenses reflects in large part incremental Finagaz expenses subsequent to its acquisition and approximately $16.3 million of acquisition and transition-related expenses. UGI International income before income taxes decreased $16.7 million principally reflecting the $9.6 million decrease in operating income and the previously mentioned $10.3 million loss resulting from an early extinguishment of debt, which is included in interest expense on the Condensed Consolidated Statements of Income. UGI International interest expense during the nine months ended June 30, 2015, excluding the $10.3 million pre-tax loss associated with the early extinguishment of debt, declined $4.2 million due in large part to the effects of the weaker euro.

Gas Utility

For the nine months ended June 30,	2015	2014	Increase (Decrease)	
(Dollars in millions)				
Revenues	$847.9	$880.0	$(32.1)	(3.6)%
Total margin (a)	$421.2	$416.5	$4.7	1.1%
Operating and administrative expenses	$150.7	$138.0	$12.7	9.2%
Operating income	$226.2	$233.7	$(7.5)	(3.2)%
Income before income taxes	$196.5	$207.1	$(10.6)	(5.1)%
System throughput—bcf —				
Core market	76.4	75.1	1.3	1.7%
Total	176.3	172.8	3.5	2.0%
Degree days—% colder than normal (b)	7.2%	10.2%	—	—

(a) Total margin represents total revenues less total cost of sales.
(b) Deviation from average heating degree days for the 15-year period 1995-2009 based upon weather statistics provided by NOAA for airports located within Gas Utility’s service territory.

Temperatures in Gas Utility’s service territory in the 2015 nine-month period based upon heating degree days were 7.2% colder than normal but 2.8% warmer than the 2014 nine-month period. Total distribution system throughput increased 3.5 bcf, notwithstanding the warmer weather, principally reflecting higher firm delivery service volumes and slightly higher core market volumes reflecting, in large part, a 1.7% increase in the number of core market customers.

Gas Utility revenues decreased $32.1 million during the 2015 nine-month period principally reflecting lower revenues from off-system sales ($30.4 million) and lower other revenues partially offset by higher revenues from core market customers ($3.0 million). The increase in core market revenues principally reflects the effects of the higher core market throughput offset by slightly lower average PGC rates during the 2015 nine-month period. Gas Utility's cost of sales was $426.7 million in the 2015 nine-month period compared with $463.5 million in the 2014 nine-month period principally reflecting the effects of the lower off-system sales ($30.4 million) and the slightly lower average PGC rates.

Gas Utility nine-month period total margin increased $4.7 million principally reflecting higher core market total margin ($6.3 million) on the higher core market sales. This increase was partially offset principally by lower margin from interruptible customers.

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Gas Utility operating income and income before income taxes during the 2015 nine-month period decreased $7.5 million and $10.6 million, respectively, compared with the prior-year period. The $7.5 million decrease in Gas Utility operating income, notwithstanding the $4.7 million higher total margin, principally reflects higher operating and administrative expenses and higher depreciation expense. Operating and administrative expenses were modestly higher than the prior-year period principally reflecting, among other things, higher 2015 nine-month period distribution system maintenance expenses ($5.3 million), higher depreciation expense ($2.7 million) and higher employee benefits and other general administrative expenses. The $10.6 million decrease in Gas Utility income before income taxes reflects the lower operating income ($7.5 million) and higher long-term debt interest expense.

Midstream & Marketing

For the nine months ended June 30,	2015	2014	Increase (Decrease)	
(Dollars in millions)				
Revenues (a)	$923.2	$1,160.3	$(237.1)	(20.4)%
Total margin (b)	$241.7	$251.6	$(9.9)	(3.9)%
Operating and administrative expenses	$55.7	$50.7	$5.0	9.9%
Operating income	$166.0	$183.7	$(17.7)	(9.6)%
Income before income taxes	$164.4	$181.2	$(16.8)	(9.3)%

(a) Amounts are net of intercompany revenues between Midstream & Marketing’s Energy Services and Electric Generation segments.

(b) Total margin represents total revenues less total cost of sales. Amounts exclude net pre-tax gains (losses) from changes in the fair values of Midstream & Marketing’s unsettled commodity derivative instruments and certain settled commodity derivative instruments not associated with current period transactions of $(42.8) million and $1.0 million during the 2015 nine-month period and the 2014 nine-month period, respectively.

Midstream & Marketing 2015 nine-month period total revenues were $237.1 million lower than the 2014 nine-month period principally reflecting lower natural gas ($183.8 million), retail power ($37.4 million), peaking ($12.5 million) and Electric Generation revenues partially offset by higher natural gas gathering revenues. The decrease in natural gas revenues principally reflects lower wholesale and retail natural gas prices during the 2015 nine-month period. The lower 2015 nine-month period retail power revenues principally reflect lower sales volumes and, to a lesser extent, lower average prices. Total capacity management revenues were about equal to the prior-year period as greater capacity management revenues during the first quarter of Fiscal 2015 were offset in large part by lower capacity management revenues during the second and third quarters of Fiscal 2015 reflecting lower average prices for capacity. Higher prices for pipeline capacity in the prior-year nine-month period began primarily during the second quarter of Fiscal 2014 during which time the Company experienced significantly higher locational basis differences due to greater volatility in capacity values between Marcellus and non-Marcellus delivery points. These higher locational basis differences continued during the 2015 nine-month period, although at lower average values than were experienced during the prior year. Midstream & Marketing cost of sales decreased to $681.5 million in the 2015 nine-month period compared to $908.7 million in the 2014 nine-month period principally reflecting lower natural gas ($172.2 million), retail power ($44.4 million) and peaking ($8.5 million) cost of sales.

Midstream & Marketing total margin decreased $9.9 million in the 2015 nine-month period principally reflecting lower natural gas marketing total margin ($11.6 million),a decline in peaking total margin ($4.0 million) and lower Electric Generation total margin($3.5 million). These declines were partially offset principally by higher total margin from retail power ($7.0 million) and higher natural gas gathering total margin ($3.2 million). The decline in natural gas marketing total margin principally reflects the effects of lower average unit margins due in large part to the timing of natural gas basis margin associated with fixed-basis customers. The lower peaking total margin in the 2015 nine-month period principally reflects lower natural gas prices while the lower Electric Generation total margin principally reflects the result of lower volumes generated due to scheduled generation plant outages earlier in the 2015 nine-month period. The higher retail power total margin reflects the effects of higher unit margins offset by the effects of lower volumes sold while the increase in natural gas gathering total margin reflects the expansion of our natural gas gathering system in the Marcellus shale region in northern Pennsylvania.

Midstream & Marketing operating income and income before income taxes during the 2015 nine-month period decreased $17.7 million and $16.8 million, respectively, principally reflecting the previously mentioned decrease in total margin ($9.9 million), higher operating and administrative costs ($5.0 million) and higher depreciation expense principally reflecting incremental depreciation associated with storage and natural gas gathering assets and higher depreciation associated with the Conemaugh generating unit. The higher operating and administrative expenses include, among other things, increased operating expenses associated with planned outages at the Hunlock Station and Conemaugh generating units earlier in the period and higher operating expenses associated with our expanded natural gas gathering assets including the impact of the Auburn pipeline extension.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2015 nine-month period was $184.7 million, slightly higher than the $178.9 million of interest expense recorded during the 2014 nine-month period. Interest expense in the 2015 nine-month period includes a $10.3 million pre-tax loss principally resulting from the settlement of interest rate swaps associated with an early extinguishment of debt at Antargaz. Excluding the effects of the pre-tax loss resulting from the extinguishment of debt at Antargaz, interest expense decreased $4.5 million principally reflecting (1) the effects of the weaker euro on UGI International interest expense and (2) lower interest expense on short-term borrowings at AmeriGas Propane and Midstream & Marketing, partially offset by higher long-term debt interest at UGI Utilities. Our effective income tax rate (excluding the effects on such rate of pre-tax income associated with noncontrolling interests not subject to federal income taxes) in the 2015 nine-month period was slightly lower than such rate calculated in the prior-year nine-month period, which included $5.7 million of income taxes associated with the change in tax laws in France that was retroactive to Fiscal 2013.

FINANCIAL CONDITION AND LIQUIDITY

We depend on both internal and external sources of liquidity to provide funds for working capital and to fund capital requirements. Our short-term cash requirements not met by cash from operations are generally satisfied with borrowings under credit facilities and, in the case of Midstream & Marketing, also from a receivables purchase facility. Long-term cash requirements not met by cash from operations are generally met through issuance of long-term debt or equity securities. We believe that each of our business units has sufficient liquidity in the forms of cash and cash equivalents on hand; cash expected to be generated from operations; credit facility and receivables purchase facility borrowings; and the ability to obtain long-term financing to meet anticipated contractual and projected cash commitments. Issuances of debt and equity securities in the capital markets and additional credit facilities may not, however, be available to us on acceptable terms.

The primary sources of UGI’s cash and cash equivalents are the dividends and other cash payments made to UGI or its corporate subsidiaries by its principal business units. Our cash and cash equivalents, excluding cash in commodity futures brokerage accounts that is restricted from withdrawal, totaled $385.9 million at June 30, 2015, compared with $419.5 million at September 30, 2014. Excluding cash and cash equivalents that reside at UGI’s operating subsidiaries, at June 30, 2015 and September 30, 2014, UGI had $68.4 million and $245.9 million of cash and cash equivalents, respectively. Such cash is available to pay dividends on UGI Common Stock and for investment purposes.

Long-term Debt and Short-term Debt

The Company’s debt outstanding at June 30, 2015, totaled $3,779.6 million (including current maturities of long-term debt of $83.3 million and short-term borrowings of $68.0 million) compared to debt outstanding at September 30, 2014, of $3,721.6 million (including current maturities of long-term debt of $77.2 million and short-term borrowings of $210.8 million). Total debt outstanding at June 30, 2015, consists of (1) $2,333.2 million of Partnership debt; (2) $790.1 million of UGI International debt; (3) $624.7 million of UGI Utilities debt; (4) $20.8 million of Energy Services debt; and (5) $10.8 million of other debt.

AmeriGas Partners. AmeriGas Partners’ total debt at June 30, 2015, includes $2,250.8 million of AmeriGas Partners’ Senior Notes, $43.6 million of AmeriGas OLP short-term borrowings and $38.8 million of other long-term debt.

UGI International. UGI International's total debt at June 30, 2015, includes $668.5 million (€600 million) outstanding under Antargaz' 2015 Senior Facilities Agreement, $52 million under Flaga's U.S. dollar-denominated term loan and a combined $65.8 million (€59.1 million) outstanding under Flaga's euro-denominated term loans. Total UGI International debt outstanding at June 30, 2015, also includes $1.7 million (€1.5 million) of Flaga short-term borrowings and $2.1 million (€1.9 million) of other long-term debt.

On May 29, 2015, UGI France (formerly UGI Bordeaux Holding), an indirect wholly owned subsidiary of UGI, borrowed €600 million ($659.6 million) under its Senior Facilities Agreement with a consortium of banks (the "2015 Senior Facilities Agreement"). UGI France entered into the 2015 Senior Facilities Agreement on April 30, 2015, in anticipation of its then-pending acquisition of Total's retail LPG distribution business in France ("Totalgaz"), which was consummated on May 29, 2015 (see Note 15 to condensed consolidated financial statements). The 2015 Senior Facilities Agreement consists of a €600 million variable-rate term loan and a €60 million revolving credit facility. The term loan proceeds were used (1) to fund a portion of the acquisition of Totalgaz, including related fees and expenses; (2) to make a capital contribution from UGI France to its wholly owned subsidiary, AGZ Holding, to prepay €342 million principal amount, plus accrued interest, outstanding under Antargaz' 2011 Senior Facilities

Agreement due March 2016 (the "2011 Senior Facilities Agreement"); (3) to settle Antargaz' existing pay-fixed, receive-variable interest rate swaps associated with the 2011 Senior Facilities Agreement; and (4) for general corporate purposes. Borrowings under the 2015 Senior Facilities Agreement €600 million term loan and the €60 million revolving credit facility bear interest at rates per annum comprising the aggregate of the applicable margin and the associated euribor rate, which euribor rate has a floor of 0.0%. UGI France has entered into pay-fixed, receive-variable interest rate swaps through April 30, 2019, to generally fix the underlying euribor rate. For further information on the 2015 Senior Facilities Agreement and the associated pay-fixed, receive-variable interest rate swaps, see Note 8 to the condensed consolidated financial statements.
As a result of prepaying the Antargaz term loan under the 2011 Senior Facilities Agreement in May 2015, we recorded a pre-tax loss of $10.3 million, which is included in interest expense on the Condensed Consolidated Statements of Income. Effective April 30, 2015, UGI International, Inc., an indirect wholly owned subsidiary of UGI, terminated, according to its terms, its €300 million Senior Secured Bridge Facility Agreement, as amended. The Senior Secured Bridge Facility Agreement had previously been entered into in order to provide an additional source of financing, if necessary, to fund a portion of the acquisition of Totalgaz.

UGI Utilities. UGI Utilities' total debt at June 30, 2015, includes $450.0 million of Senior Notes, $172.0 million of Medium-Term Notes and $2.7 million of short-term borrowings.

Short-term Debt

Additional information related to the Company's credit agreements can be found in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in the Company's 2014 Annual Report. The discussion below provides updates to this information during the nine months ended June 30, 2015.

UGI Utilities. On March 27, 2015, UGI Utilities entered into an unsecured revolving credit agreement (the "UGI Utilities 2015 Credit Agreement") with a group of banks providing for borrowings up to $300 million (including a $100 million sublimit for letters of credit). Concurrently with entering into the UGI Utilities 2015 Credit Agreement, UGI Utilities terminated its then-existing $300 million revolving credit agreement dated as of May 25, 2011. Under the UGI Utilities 2015 Credit Agreement, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The UGI Utilities 2015 Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.0. The UGI Utilities 2015 Credit Agreement is currently scheduled to expire in March 2016, but may be extended by UGI Utilities to March 2020 if on or before March 25, 2016, the Company receives approval for the UGI Utilities 2015 Credit Agreement by the PUC. UGI Utilities filed to obtain such approval on June 30, 2015.

UGI International. Flaga has two principal working capital facilities (the "Flaga Credit Agreements") comprising (1) a €46 million multi-currency working capital facility that includes an uncommitted €6 million overdraft facility (the "Flaga Multi-Currency Working Capital Facility"), and (2) a euro-denominated working capital facility that provides for borrowings and issuances of guarantees totaling €12 million (the "Euro Facility"), both of which are scheduled to expire in September 2015. Flaga expects to extend these facilities prior to their expiration in September 2015. As previously mentioned, UGI France entered into the 2015 Senior Facilities Agreement, which includes a €60 million revolving credit facility that expires in April 2020.

Information about the Company's principal credit agreements (excluding the Energy Services Receivables Facility discussed below) as of June 30, 2015 and 2014, is presented in the table below.

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(Millions of dollars or euros)	Total Capacity	Borrowings Outstanding	Letters of Credit and Guarantees Outstanding	Available Capacity
As of June 30, 2015				
AmeriGas Propane	$525.0	$43.6	$64.7	$416.7
Antargaz	€60.0	€0.0	€0.0	€60.0
Flaga	€58.0	€1.5	€20.0	€36.5
UGI Utilities	$300.0	$2.7	$2.0	$295.3
Energy Services	$240.0	$0.0	$0.0	$240.0
As of June 30, 2014				
AmeriGas Propane	$525.0	$92.5	$64.7	$367.8
Antargaz	€40.0	€0.0	€0.0	€40.0
Flaga	€58.0	€0.0	€32.3	€25.7
UGI Utilities	$300.0	$0.0	$2.0	$298.0
Energy Services	$240.0	$0.0	$0.0	$240.0

The average daily and peak short-term borrowings under the Company's principal credit agreements during the nine months ended June 30, 2015 and 2014 are as follows:

	For the nine months ended June 30, 2015		For the nine months ended June 30, 2014	
(Millions of dollars or euros)	Average	Peak	Average	Peak
AmeriGas Propane	$136.9	$349.0	$175.0	$320.0
Antargaz	N.A.	N.A.	N.A.	N.A.
Flaga	€2.9	€3.6	€1.5	€3.6
UGI Utilities	$73.6	$163.6	$30.4	$84.0
Energy Services	$0.2	$7.0	$55.4	$114.0

Energy Services also has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2015. The Receivables Facility provides Energy Services with the ability to borrow up to $150 million of eligible receivables during the period November through May and up to $75 million of eligible receivables during the period June through October. Energy Services uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts, capital expenditures, dividends and for general corporate purposes. Energy Services intends to extend its Receivables Facility prior to its scheduled expiration.

Under the Receivables Facility, Energy Services transfers, on an ongoing basis and without recourse, its trade accounts receivable to its wholly owned, special purpose subsidiary, ESFC, which is consolidated for financial statement purposes. ESFC, in turn, has sold, and subject to certain conditions, may from time to time sell, an undivided interest in some or all of the receivables to a major bank. At June 30, 2015, the outstanding balance of ESFC trade receivables was $42.9 million of which $20.0 was sold to the bank. At June 30, 2014, the outstanding balance of ESFC trade receivables was $57.7 million and there were no amounts sold to the bank. Amounts sold to the bank are reflected as short-term borrowings on the Condensed Consolidated Balance Sheets.

During the nine months ended June 30, 2015 and 2014, Energy Services transferred trade receivables to ESFC totaling $873.4 million and $1,073.1 million, respectively. During the nine months ended June 30, 2015 and 2014, ESFC sold an aggregate $272.5 million and $196.0 million, respectively, of undivided interests in its trade receivables to the bank. During the nine months ended June 30, 2015 and 2014, peak sales of receivables were $67.5 million and $70.0

million, respectively, and average daily amounts sold were $18.5 million and $19.2 million, respectively.

Dividends and Distributions

On July 28, 2015, UGI’s Board of Directors approved a quarterly dividend of $0.2275 per common share payable October 1, 2015, to shareholders of record on September 15, 2015. On April 28, 2015, UGI’s Board of Directors approved an increase in the quarterly dividend rate on UGI Common Stock to $0.2275 per Common Share, or $0.91 on an annual basis. The dividend rate

reflects an approximately 4.6% increase from the previous quarterly rate of $0.2175. The new quarterly dividend rate was effective with the dividend payable on July 1, 2015, to shareholders of record on June 15, 2015.
On July 27, 2015, the General Partner’s Board of Directors approved a quarterly distribution of $0.92 per Common Unit payable August 18, 2015, to unitholders of record on August 10, 2015. On April 27, 2015, the General Partner’s Board of Directors approved an increase in the quarterly dividend rate on AmeriGas Partners Common Units to $0.92 per Common Unit, equal to an annual rate of $3.68 per Common Unit. The distribution reflects a 4.5% increase from the previous quarterly rate of $0.88. The new quarterly rate was effective with the distribution payable on May 18, 2015, to unitholders of record on May 11, 2015.

Cash Flows

Due to the seasonal nature of the Company’s businesses, cash flows from operating activities are generally strongest during the second and third fiscal quarters when customers pay for natural gas, LPG, electricity and other energy products and services consumed during the peak heating season months. Conversely, operating cash flows are generally at their lowest levels during the fourth and first fiscal quarters when the Company’s investment in working capital, principally inventories and accounts receivable, is generally greatest.

Operating Activities. Cash flow provided by operating activities was $968.1 million in the 2015 nine-month period compared to cash flow provided by operating activities of $858.1 million in the 2014 nine-month period. The Company’s operating cash flow during the nine months ended June 30, 2015, benefited from lower net operating working capital amounts as a result of significant declines in LPG and natural gas commodity costs. Cash flow from operating activities before changes in operating working capital was $860.3 million in the 2015 nine-month period compared to $921.9 million in the prior-year period. Cash provided by changes in operating working capital totaled $107.8 million in the 2015 nine-month period compared to cash used to fund operating working capital of $63.8 million in the prior-year period. The significant increase in cash provided by changes in operating working capital reflects, in large part, the impact of the previously mentioned significant decline in LPG and natural gas commodity costs.

Investing Activities. Cash flow used by investing activities was $775.0 million in the 2015 nine-month period compared with $337.4 million in the prior-year period. Investing activity cash flow is principally affected by expenditures for property, plant and equipment; cash paid for acquisitions of businesses; changes in restricted cash balances; and proceeds from sales of assets. Cash used for acquisitions of businesses includes cash paid for the Totalgaz Acquisition, net of cash acquired, of $412.9 million. Cash payments for property, plant and equipment were $330.4 million in the 2015 nine-month period compared to $325.5 million in the prior-year period. The significant increase in restricted cash during the 2015 nine-month period reflects the impact of the previously mentioned decline in energy commodity prices on cash margin requirements in our NYMEX brokerage accounts.

Financing Activities. Cash flow used by financing activities was $207.3 million in the 2015 nine-month period compared with $475.4 million in the prior-year period. Changes in cash flow from financing activities are primarily due to issuances and repayments of long-term debt; net short-term borrowings; dividends and distributions on UGI Common Stock and AmeriGas Partners Common Units; and issuances of UGI and AmeriGas Partners equity instruments. Financing cash flows in the 2015 nine-month period include net proceeds from the issuance of long-term debt under the 2015 Senior Facilities Agreement totaling $652.6 million, the proceeds of which were used principally to fund a portion of the Totalgaz Acquisition and to prepay term loans outstanding under the 2011 Senior Facilities Agreement.

The decrease in cash from changes in foreign currency exchange rates during the 2015 nine-month period reflects the effects of the significantly weaker euro and British pound sterling on cash balances at our UGI International business units.

Acquisition of Totalgaz

On May 29, 2015 (“Closing Date”), UGI Corporation’s indirect wholly owned subsidiary UGI France acquired all of the outstanding shares of Totalgaz (referred to as Finagaz from and after the Closing Date), Total’s retail LPG distribution business in France, for a purchase price at the Closing Date of €453.0 million ($497.8 million) in cash, including €30.0 million ($33.0 million) for estimated Closing Date working capital, subject to working capital and other adjustments (“Totalgaz Acquisition”). Totalgaz serves residential, commercial, industrial and autogas customers and the acquisition nearly doubles UGI’s retail LPG distribution business in France.

The purchase price for the acquisition of Totalgaz was funded on the Closing Date from existing cash balances as well as from a portion of the €600 million proceeds from a term loan issued on May 29, 2015, under UGI France’s previously mentioned 2015 Senior Facilities Agreement. The results of operations of Finagaz are included in the Condensed Consolidated Income Statement since the Closing Date. For additional information on the Totalgaz Acquisition, see Note 15 to condensed consolidated financial statements.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk exposures are (1) commodity price risk; (2) interest rate risk; and (3) foreign currency exchange rate risk. Although we use derivative financial and commodity instruments to reduce market price risk associated with forecasted transactions, we do not use derivative financial and commodity instruments for speculative or trading purposes.

Commodity Price Risk

The risk associated with fluctuations in the prices the Partnership and our UGI International operations pay for LPG is principally a result of market forces reflecting changes in supply and demand for propane and other energy commodities. Their profitability is sensitive to changes in LPG supply costs. Increases in supply costs are generally passed on to customers. The Partnership and UGI International may not, however, always be able to pass through product cost increases fully or on a timely basis, particularly when product costs rise rapidly. In order to reduce the volatility of LPG market price risk, the Partnership uses contracts for the forward purchase or sale of propane, propane fixed-price supply agreements and over-the-counter derivative commodity instruments including price swap and option contracts. Our UGI International operations use over-the-counter derivative commodity instruments and may from time to time enter into other derivative contracts, similar to those used by the Partnership, to reduce market risk associated with a portion of their LPG purchases. Over-the-counter derivative commodity instruments used to economically hedge forecasted purchases of propane are generally settled at expiration of the contract. In addition, Antargaz hedges a portion of its future U.S. dollar-denominated LPG product purchases through the use of forward foreign exchange contracts as further described below.

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to its customers, including the cost of financial instruments used to hedge purchased gas costs. The recovery clauses provide for periodic adjustments for the difference between the total amounts actually collected from customers through PGC rates and the recoverable costs incurred. Because of this ratemaking mechanism, there is limited commodity price risk associated with our Gas Utility operations. Gas Utility uses derivative financial instruments, including natural gas futures and option contracts traded on the NYMEX to reduce volatility in the cost of gas it purchases for its retail core-market customers. The cost of these derivative financial instruments, net of any associated gains or losses, is included in Gas Utility's PGC recovery mechanism. At June 30, 2015, the fair values of Gas Utility’s natural gas futures and option contracts were net losses of $0.7 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of FTRs and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2015, the fair values of Electric Utility’s electricity supply contracts were net losses of $1.4 million. At June 30, 2015, the fair values of Electric Utility’s FTRs were not material.

In order to manage market price risk relating to substantially all of Midstream & Marketing’s fixed-price sales contracts for natural gas and electricity, Midstream & Marketing enters into NYMEX, ICE and over-the-counter natural gas and electricity futures and natural gas basis swap contracts or enters into fixed-price supply arrangements. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to economically hedge a portion of its anticipated sales of electricity from its electricity generation facilities. Although Midstream &

Marketing's fixed-price supply arrangements mitigate most risks associated with its fixed-price sales contracts, should any of the suppliers under these arrangements fail to perform, increases, if any, in the cost of replacement natural gas or electricity would adversely impact Midstream & Marketing's results. In order to reduce this risk of supplier nonperformance, Midstream & Marketing has diversified its purchases across a number of suppliers.

Midstream & Marketing purchases FTRs to economically hedge certain transmission costs that may be associated with its fixed-price electricity sales contracts. Midstream & Marketing from time to time also enters into NYISO capacity swap contracts to economically hedge the locational basis differences for customers it serves on the NYISO electricity grid. Midstream & Marketing also uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later sale of natural gas or propane.

Midstream & Marketing has entered into fixed-price sales agreements for a portion of the electricity expected to be generated by its electric generation assets. In the event that these generation assets would not be able to produce all of the electricity needed to supply electricity under these agreements, Midstream & Marketing would be required to purchase electricity on the spot market or under contract with other electricity suppliers. Accordingly, increases in the cost of replacement power could negatively impact Midstream & Marketing's results.

The fair value of unsettled commodity price risk sensitive derivative instruments held at June 30, 2015 (excluding those Gas Utility and Electric Utility commodity derivative instruments that are refundable to, or recoverable from, customers) was a loss of $127.9 million. A hypothetical 10% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would increase such loss by approximately $54.0 million at June 30, 2015.

Interest Rate Risk

We have both fixed-rate and variable-rate debt. Changes in interest rates impact the cash flows of variable-rate debt but generally do not impact their fair value. Conversely, changes in interest rates impact the fair value of fixed-rate debt but do not impact their cash flows.

Our variable-rate debt at June 30, 2015, includes our short-term borrowings and Antargaz' and Flaga's variable-rate term loans. These debt agreements have interest rates that are generally indexed to short-term market interest rates. Antargaz and Flaga have effectively fixed the underlying euribor interest rates on their term loans through their scheduled maturity dates through the use of interest rate swaps. In addition, Flaga's $52.0 million U.S. dollar-denominated loan has been swapped from fixed-rate U.S. dollars to fixed-rate euro currency at issuance through cross currency swaps, removing interest rate risk and foreign currency exchange risk associated with the underlying interest and principal payments. At June 30, 2015, combined borrowings outstanding under these variable-rate debt agreements, excluding Antargaz' and Flaga's effectively fixed-rate debt, totaled $68.0 million.

The fair value of unsettled interest rate risk sensitive derivative instruments held at June 30, 2015 (including pay-fixed, receive-variable interest rate swaps) was a loss of $0.9 million. A 50 basis point adverse change in the three-month euribor rate would result in a decrease in fair value of approximately $13.1 million.

Foreign Currency Exchange Rate Risk

Our primary currency exchange rate risk is associated with the U.S. dollar versus the euro. The U.S. dollar value of our foreign currency denominated assets and liabilities will fluctuate with changes in the associated foreign currency exchange rates. From time to time, we use derivative instruments to hedge portions of our net investments in foreign subsidiaries ("net investment hedges"). Gains or losses on net investment hedges remain in accumulated other comprehensive income until such foreign operations are liquidated. At June 30, 2015, there were no unsettled net investment hedges outstanding. With respect to our net investments in our UGI International operations, a 10% decline in the value of the associated foreign currencies versus the U.S. dollar, excluding the effects of any net investment hedges, would reduce their aggregate net book value at June 30, 2015, by approximately $105.0 million, which amount would be reflected in other comprehensive income.

In addition, in order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases during the months of October through March through the use of forward foreign exchange contracts.

The fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at June 30, 2015, was a gain of $37.2 million. A hypothetical 10% adverse change in the value of the euro versus the U.S. dollar would result in a decrease in fair value of approximately $15.4 million.

Derivative Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative instrument counterparties. Our derivative instrument counterparties principally comprise large energy companies and major U.S. and international financial institutions. We maintain credit policies with regard to our counterparties that we believe reduce overall credit risk. These policies include evaluating and monitoring our counterparties' financial condition, including their credit ratings, and entering into agreements with counterparties that govern credit limits or entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. Certain of these agreements call for the posting of collateral by the counterparty or by the Company in the forms of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2015 and 2014, restricted cash in brokerage accounts totaled $45.2 million and $5.9 million, respectively. Although we have concentrations of credit risk associated with derivative instruments, the maximum amount of loss, based upon the gross fair values of the derivative instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at June 30, 2015. Certain of the Partnership's derivative contracts have credit-risk-related contingent features that may require the posting of additional collateral in the event of a downgrade of the Partnership's debt rating. At June 30, 2015, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

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ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports filed or submitted under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and (ii) accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company’s Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were effective at the reasonable assurance level.

(b) Change in Internal Control over Financial Reporting

During the quarter ended June 30, 2015, other than changes resulting from the Totalgaz Acquisition discussed below, no change in the Company’s internal control over financial reporting occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

On May 29, 2015, UGI France, an indirect wholly owned subsidiary of UGI Corporation, acquired Totalgaz. The Company is currently in the process of integrating operations, processes and internal controls. See Note 15 to condensed consolidated financial statements for additional information related to the Totalgaz Acquisition.

UGI CORPORATION AND SUBSIDIARIES

PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS
In addition to the information presented in this report, you should carefully consider the factors discussed in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended September 30, 2014, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing the Company. Other unknown or unpredictable factors could also have material adverse effects on future results.

ITEM 6. EXHIBITS
The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and last date of the period for which it was filed, and the exhibit number in such filing):

Incorporation by Reference

Exhibit No.	Exhibit	Registrant	Filing	Exhibit
3.1	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of AmeriGas Partners, L.P. dated as of July 27, 2015.	AmeriGas Partners, L.P.	Form 8-K (7/27/15)	3.1
10.1	Senior Facilities Agreement dated April 30, 2015 by and among UGI France, as Borrower, Guarantor and Security Grantor, Natixis, as Facility Agent and Security Agent, Barclays Bank PLC, BNP Paribas, Caisse Régionale de Crédit Agricole Mutuel de Paris et d'Ile de France, Crédit Lyonnais SA, ING Bank N.V. (acting through its French branch), Société Générale Corporate & Investment Banking, and Natixis, as Mandated Lead Arrangers, Underwriters and Bookrunners, and HSBC France, as Senior Mandated Lead Arranger.			
31.1	Certification by the Chief Executive Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.2	Certification by the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL Instance			
101.SCH	XBRL Taxonomy Extension Schema			

101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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SIGNATURES

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.

UGI Corporation
(Registrant)

Date: August 7, 2015

By: /s/ Kirk R. Oliver
Kirk R. Oliver
Chief Financial Officer

Date: August 7, 2015

By: /s/ Davinder S. Athwal
Davinder S. Athwal
Vice President - Accounting and
Financial Control and Chief Risk Officer

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EXHIBIT INDEX

10.1	Senior Facilities Agreement dated April 30, 2015 by and among UGI France, as Borrower, Guarantor and Security Grantor, Natixis, as Facility Agent and Security Agent, Barclays Bank PLC, BNP Paribas, Caisse Régionale de Crédit Agricole Mutuel de Paris et d'Ile de France, Crédit Lyonnais SA, ING Bank N.V. (acting through its French branch), Société Générale Corporate & Investment Banking, and Natixis, as Mandated Lead Arrangers, Underwriters and Bookrunners, and HSBC France, as Senior Mandated Lead Arranger.
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