UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended December 31, 2014

OR

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

For the transition period from ________ to ________

Commission file number 1-11071

UGI CORPORATION

(Exact name of registrant as specified in its charter)

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

At January 31, 2015, there were 172,787,331 shares of UGI Corporation Common Stock, without par value, outstanding.

UGI CORPORATION AND SUBSIDIARIES

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UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)
(Millions of dollars)

	December 31, 2014	September 30, 2014	December 31, 2013
ASSETS			
Current assets:			
Cash and cash equivalents	$ 410.1	$ 419.5	$ 418.1
Restricted cash	54.6	16.6	4.5
Accounts receivable (less allowances for doubtful accounts of $37.9, $39.1 and $43.8, respectively)	960.6	684.7	1,204.0
Accrued utility revenues	52.7	14.3	66.4
Inventories	391.0	423.0	412.4
Deferred income taxes	46.1	10.1	23.0
Utility regulatory assets	16.8	13.2	0.4
Derivative instruments	19.7	14.5	51.6
Prepaid expenses and other current assets	88.0	67.1	47.1
Total current assets	2,039.6	1,663.0	2,227.5
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,664.2, $2,633.0 and $2,630.9, respectively)	4,552.7	4,543.7	4,517.1
Goodwill	2,806.8	2,833.4	2,884.5
Intangible assets, net	563.7	576.4	598.8
Derivative instruments	16.1	12.5	2.2
Other assets	451.1	464.0	433.4
Total assets	$ 10,430.0	$ 10,093.0	$ 10,663.5
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 147.1	$ 77.2	$ 67.2
Short-term borrowings	458.5	210.8	421.5
Accounts payable	556.5	459.8	691.4
Derivative instruments	157.0	40.2	20.8
Other current liabilities	649.7	642.9	678.6
Total current liabilities	1,968.8	1,430.9	1,879.5
Long-term debt	3,341.2	3,433.6	3,549.1
Deferred income taxes	976.3	1,005.1	980.2
Deferred investment tax credits	3.8	3.9	4.2
Derivative instruments	39.9	16.6	22.4
Other noncurrent liabilities	545.3	539.7	509.4
Total liabilities	6,875.3	6,429.8	6,944.8
Commitments and contingencies (Note 8)			
Equity:			
UGI Corporation stockholders' equity:			
UGI Common Stock, without par value (authorized—450,000,000 shares; issued—173,772,391, 173,770,641 and 173,675,691 shares, respectively)	1,215.7	1,215.6	1,210.0
Retained earnings	1,506.0	1,509.4	1,397.9
Accumulated other comprehensive (loss) income	(40.1)	(21.2)	32.2
Treasury stock, at cost	(35.3)	(44.7)	(30.5)
Total UGI Corporation stockholders' equity	2,646.3	2,659.1	2,609.6
Noncontrolling interests, principally in AmeriGas Partners	908.4	1,004.1	1,109.1
Total equity	3,554.7	3,663.2	3,718.7
Total liabilities and equity	$ 10,430.0	$ 10,093.0	$ 10,663.5

See accompanying notes to condensed consolidated financial statements.

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UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31,	
	2014	2013
Revenues	$ 2,004.6	$ 2,315.9
Costs and expenses:		
Cost of sales (excluding depreciation shown below)	1,404.6	1,429.9
Operating and administrative expenses	435.7	431.5
Utility taxes other than income taxes	4.1	4.2
Depreciation	75.8	78.6
Amortization	15.2	15.4
Other operating income, net	(14.1)	(7.4)
	1,921.3	1,952.2
Operating income	83.3	363.7
Loss from equity investees	(1.0)	—
Interest expense	(59.0)	(59.3)
Income before income taxes	23.3	304.4
Income tax expense	(23.1)	(86.9)
Net income	0.2	217.5
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	33.9	(95.5)
Net income attributable to UGI Corporation	$ 34.1	$ 122.0
Earnings per common share attributable to UGI Corporation stockholders:		
Basic	$ 0.20	$ 0.71
Diluted	$ 0.19	$ 0.70
Average common shares outstanding (thousands):		
Basic	172,945	172,238
Diluted	175,786	174,705
Dividends declared per common share	$ 0.2175	$ 0.1883

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31,	
	2014	2013
Net income	$ 0.2	$ 217.5
Other comprehensive income (loss):		
Net gains on derivative instruments (net of tax of $(3.9) and $(7.5), respectively)	7.7	40.5
Reclassifications of net losses (gains) on derivative instruments (net of tax of $(1.5) and $2.0, respectively)	2.1	(13.8)
Foreign currency adjustments (net of tax of $15.6 and $(3.7), respectively)	(30.5)	12.3
Benefit plans (net of tax of $(0.4) and $0.1, respectively)	0.6	0.4
Other comprehensive (loss) income	(20.1)	39.4
Comprehensive (loss) income	(19.9)	256.9
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	35.0	(111.1)
Comprehensive income attributable to UGI Corporation	$ 15.1	$ 145.8

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 0.2	$ 217.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	91.0	94.0
Deferred income tax benefit, net	(59.8)	(19.7)
Provision for uncollectible accounts	7.0	8.9
Unrealized losses (gains) on derivative instruments	229.7	(5.2)
Other, net	(0.9)	0.8
Net change in:		
Accounts receivable and accrued utility revenues	(341.8)	(508.2)
Inventories	27.6	(45.1)
Utility deferred fuel and power costs, net of changes in unsettled derivatives	4.4	2.1
Accounts payable	119.3	245.9
Collateral deposits	(90.9)	—
Other current assets	(14.9)	5.2
Other current liabilities	48.1	76.7
Net cash provided by operating activities	19.0	72.9
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(132.1)	(133.1)
Acquisitions of businesses, net of cash acquired	(7.2)	(20.8)
(Increase) decrease in restricted cash	(38.0)	3.8
Other, net	7.0	1.3
Net cash used by investing activities	(170.3)	(148.8)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(37.5)	(32.4)
Distributions on AmeriGas Partners publicly held Common Units	(60.8)	(58.0)
Repayments of debt	(2.6)	(4.1)
Increase in short-term borrowings	213.0	188.2
Receivables Facility net borrowings	35.5	5.5
Issuances of UGI Common Stock	5.5	1.7
Other	(3.3)	0.2
Net cash provided by financing activities	149.8	101.1
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(7.9)	3.6
Cash and cash equivalents (decrease) increase	$ (9.4)	$ 28.8
Cash and cash equivalents:		
End of period	$ 410.1	$ 418.1
Beginning of period	419.5	389.3
(Decrease) increase	$ (9.4)	$ 28.8

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013
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	(3.9)	0.2
Excess tax benefits realized on equity-based compensation	1.8	0.3
Equity-based compensation expense	2.2	1.4
Balance, end of period	$ 1,215.7	$ 1,210.0
Retained earnings		
Balance, beginning of period	$ 1,509.4	$ 1,308.3
Net income attributable to UGI Corporation	34.1	122.0
Cash dividends on Common Stock	(37.5)	(32.4)
Balance, end of period	$ 1,506.0	$ 1,397.9
Accumulated other comprehensive (loss) income		
Balance, beginning of period	$ (21.2)	$ 8.4
Net gains on derivative instruments, net of tax	7.7	15.3
Reclassification of net losses (gains) on derivative instruments, net of tax	3.3	(4.2)
Benefit plans, net of tax	0.6	0.4
Foreign currency, net of tax	(30.5)	12.3
Balance, end of period	$ (40.1)	$ 32.2
Treasury stock		
Balance, beginning of period	$ (44.7)	$ (32.3)
Common stock issued in connection with employee and director plans, net of tax withheld	9.8	1.9
Reacquired common stock - employee and director plans	(0.4)	(0.1)
Balance, end of period	$ (35.3)	$ (30.5)
Total UGI Corporation stockholders' equity	$ 2,646.3	$ 2,609.6
Noncontrolling interests		
Balance, beginning of period	$ 1,004.1	$ 1,055.4
Net (loss) income attributable to noncontrolling interests, principally in AmeriGas Partners	(33.9)	95.5
Net gains on derivative instruments	—	25.2
Reclassification of net gains on derivative instruments	(1.2)	(9.6)
Dividends and distributions	(60.8)	(58.0)
Other	0.2	0.6
Balance, end of period	$ 908.4	$ 1,109.1
Total equity	$ 3,554.7	$ 3,718.7

See accompanying notes to condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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" or "we."

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 December 31, 2014, the General Partner held a 1% general partner interest and 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 69,117,556 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 three months ended December 31, 2014 and 2013 were $6.5 and $5.4, 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."

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."

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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 December 31,	
	2014	2013
Denominator (thousands of shares):		
Average common shares outstanding for basic computation	172,945	172,238
Incremental shares issuable for stock options and awards	2,841	2,467
Average common shares outstanding for diluted computation	175,786	174,705

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") exemption 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 which 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 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. Midstream & Marketing has not applied cash flow hedge accounting for its commodity derivative instruments during any of the periods presented. 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 11.

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.

Note 3 — Accounting Changes

Accounting Standards Not Yet Adopted

Extraordinary Items. In January 2015, the Financial Accounting Standards Board ("FASB") issued new accounting guidance which eliminates the concept of an extraordinary item. Under current accounting guidance, to be considered an extraordinary item an event or transaction must be both unusual in nature and must occur infrequently. Under the new guidance, the concept of an extraordinary item has been eliminated. As a result, an entity will no longer be permitted to segregate an extraordinary item from its results of operations; present an extraordinary item, net of tax, after income from continuing operations; or disclose earnings per share data applicable to an extraordinary item. The new guidance does not affect, however, the reporting and disclosure requirements for an event that is unusual in nature or that occurs infrequently. The guidance is effective for annual periods beginning after December 31, 2015 and interim periods within those annual periods. Early adoption is permitted. Entities may apply the guidance prospectively or retrospectively. If an entity chooses to apply the new guidance prospectively, it must disclose whether amounts included in income from continuing operations include items that would have qualified as extraordinary items previously. We expect to adopt the new guidance in Fiscal 2017.

Revenue Recognition. In May 2014, the FASB issued Accounting Standards Update ("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 beginning in Fiscal 2018 and allows for either full retrospective adoption or modified retrospective adoption. The Company is in the process of assessing the impact of the adoption of ASU 2014-09 on its results of operations, cash flows and financial position.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Note 4 — Inventories

Inventories comprise the following:

	December 31, 2014	September 30, 2014	December 31, 2013
Non-utility LPG and natural gas	$ 260.4	$ 283.6	$ 282.9
Gas Utility natural gas	72.4	82.7	69.1
Materials, supplies and other	58.2	56.7	60.4
Total inventories	$ 391.0	$ 423.0	$ 412.4

At December 31, 2014, UGI Utilities is a party to four principal storage contract administrative agreements ("SCAAs") having terms of one to 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 December 31, 2014, 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 December 31, 2014, September 30, 2014 and December 31, 2013, comprising 3.4 billion cubic feet ("bcf"), 3.9 bcf and 3.1 bcf of natural gas, was $14.4, $16.8 and $12.3, respectively.

Note 5 — Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	December 31, 2014	September 30, 2014	December 31, 2013
Goodwill (not subject to amortization)	$ 2,806.8	$ 2,833.4	$ 2,884.5
Intangible assets:			
Customer relationships, noncompete agreements and other	$ 709.3	$ 712.0	$ 709.6
Accumulated amortization	(271.9)	(263.8)	(243.0)
Intangible assets, net (definite-lived)	437.4	448.2	466.6
Trademarks and tradenames (indefinite-lived)	126.3	128.2	132.2
Total intangible assets, net	$ 563.7	$ 576.4	$ 598.8

The decrease in goodwill and intangible assets at December 31, 2014, includes the effects of currency translation. Amortization expense of intangible assets was $13.0 and $13.3 for the three months ended December 31, 2014 and 2013, 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 — $38.6; Fiscal 2016 — $44.9; Fiscal 2017 — $38.3; Fiscal 2018 — $36.6; Fiscal 2019 — $35.0.

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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:

	December 31, 2014	September 30, 2014	December 31, 2013
Regulatory assets (a):			
Income taxes recoverable	$ 111.1	$ 110.7	$ 106.4
Underfunded pension and postretirement plans	107.8	110.1	92.8
Environmental costs	14.7	14.6	14.9
Deferred fuel and power costs	16.7	11.8	0.4
Removal costs, net	17.6	16.8	13.7
Other	2.7	4.2	5.7
Total regulatory assets	$ 270.6	$ 268.2	$ 233.9
Regulatory liabilities (a):			
Postretirement benefits	$ 19.0	$ 18.6	$ 16.8
Environmental overcollections	0.2	0.3	2.3
Deferred fuel and power refunds	—	0.3	7.5
State tax benefits—distribution system repairs	10.3	10.1	8.7
Other	3.4	3.2	1.3
Total regulatory liabilities	$ 32.9	$ 32.5	$ 36.6

(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 which 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 December 31, 2014, September 30, 2014 and December 31, 2013 were $(6.8), $(1.4) and $2.0, respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Because we have chosen not to elect the NPNS exception under GAAP related to these derivative instruments, these electricity supply contracts are recognized on the balance sheet at fair value with an associated adjustment to regulatory assets or liabilities because Electric Utility is entitled to fully recover its DS costs. At December 31, 2014, September 30, 2014, and December 31, 2013, the fair values of Electric Utility's electricity supply contracts were gains (losses) of $(2.4), $0.3 and $(3.2), respectively. These amounts are reflected in current derivative assets and current 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.

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 December 31, 2014, September 30, 2014, and December 31, 2013, were not material.

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 three months ended December 31, 2014 and 2013, Energy Services transferred trade receivables to ESFC totaling $286.4 and $269.0, respectively. During the three months ended December 31, 2014 and 2013, ESFC sold an aggregate $105.0 and $92.0, respectively, of undivided interests in its trade receivables to the bank. At December 31, 2014, the outstanding balance of ESFC receivables was $96.5 of which $43.0 was sold to the bank. At December 31, 2013, the outstanding balance of ESFC receivables was $88.5 of which $35.5 was sold to the bank. Losses on sales of receivables to the bank during the three months ended December 31, 2014 and 2013, which are included in interest expense on the Condensed Consolidated Statements of Income, were not material.

Note 8 — 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 December 31, 2014 and 2013, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $11.2 and $12.1, respectively. We have recorded associated regulatory assets in equal amounts because recovery of these costs from CPG 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.

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 December 31, 2014, 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

Federal Trade Commission Investigation of Propane Grill Cylinder Filling Practices. On or about November 4, 2011, the General Partner received notice that the Federal Trade Commission ("FTC") had initiated an antitrust and consumer protection investigation into certain practices of the Partnership relating to the filling of portable propane cylinders. On February 2, 2012, the Partnership received a Civil Investigative Demand from the FTC that requested documents and information concerning, among other things, (i) the Partnership's decision, in 2008, to reduce the volume of propane in cylinders it sells to consumers from 17 pounds to 15 pounds, and (ii) cross-filling, related service arrangements and communications regarding the foregoing with competitors. The Partnership responded to that subpoena and cooperated with subsequent requests for information. On March 27, 2014, the FTC issued an administrative complaint against the Partnership and UGI alleging that the General Partner and one of its competitors colluded in 2008 to persuade its common customer, Walmart Stores, Inc., to accept the cylinder fill reduction from 17 pounds to 15 pounds. The complaint does not seek monetary remedies. The Partnership and UGI filed their answer to the complaint on April 18, 2014. On August 25, 2014, the parties entered into an Agreement Containing Consent Orders, and on August 27, 2014, the FTC issued an Order Withdrawing Matter from Adjudication for the Purpose of Considering a Proposed Consent Agreement. The consent agreement was accepted by the FTC on October 31, 2014. Following a public comment period, the FTC on January 7, 2015 approved a final order settling the charges. The order sets forth the conditions of settlement between the parties and concludes the FTC's investigation.

Purported Class Action Lawsuits. Following the issuance of the FTC's administrative complaint described above, more than 35 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 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 Western District of Missouri. 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.

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Note 9 — 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.

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended December 31,	2014	2013	2014	2013
Service cost	$ 2.4	$ 2.3	$ 0.2	$ 0.1
Interest cost	6.3	6.4	0.2	0.2
Expected return on assets	(7.9)	(7.3)	(0.2)	(0.1)
Amortization of:				
Prior service cost (benefit)	0.1	0.1	(0.1)	(0.1)
Actuarial loss	2.5	1.9	—	—
Net benefit cost	3.4	3.4	0.1	0.1
Change in associated regulatory liabilities	—	—	0.9	0.9
Net expense	$ 3.4	$ 3.4	$ 1.0	$ 1.0

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 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 three months ended December 31, 2014 and 2013, the Company made cash contributions to the U.S. Pension Plan of $2.8 and $3.5, respectively. The Company expects to make additional discretionary cash contributions of $8.3 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 three months ended December 31, 2014 and 2013.

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 $0.8 in the three months ended December 31, 2014 and 2013, respectively.

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Note 10 — 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 December 31, 2014, September 30, 2014 and December 31, 2013:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
December 31, 2014:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 14.1	$ 26.1	$ —	$ 40.2
Foreign currency contracts	$ —	$ 18.7	$ —	$ 18.7
Interest rate contracts	$ —	$ 0.1	$ —	$ 0.1
Cross-currency swaps	$ —	$ 4.3	$ —	$ 4.3
Liabilities:				
Commodity contracts	$ (69.4)	$ (228.5)	$ —	$ (297.9)
Interest rate contracts	$ —	$ (17.0)	$ —	$ (17.0)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 31.4	$ —	$ —	$ 31.4
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
December 31, 2013 (b):				
Derivative instruments:				
Assets:				
Commodity contracts	$ 9.8	$ 49.6	$ —	$ 59.4
Foreign currency contracts	$ —	$ 0.4	$ —	$ 0.4
Liabilities:				
Commodity contracts	$ (6.1)	$ (4.6)	$ —	$ (10.7)
Foreign currency contracts	$ —	$ (7.2)	$ —	$ (7.2)
Interest rate contracts	$ —	$ (29.2)	$ —	$ (29.2)
Cross-currency swaps	$ —	$ (2.1)	$ —	$ (2.1)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 30.3	$ —	$ —	$ 30.3

(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.

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 which 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 December 31, 2014, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,488.3 and $3,640.7, respectively. At December 31, 2013, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,616.3 and $3,856.9, 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 which extends across many different U.S. markets and several foreign countries. For information regarding concentrations of credit risk associated with our derivative instruments, see Note 11. 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 11 — 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. In addition, 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 December 31, 2014 and 2013, total volumes associated with LPG commodity derivative instruments totaled 429.6 million gallons and 215.2 million gallons, respectively. At December 31, 2014, the maximum period over which we are economically hedging our exposure to LPG commodity price risk is 33 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 December 31, 2014 and 2013, the volumes of natural gas associated with Gas Utility’s unsettled NYMEX natural gas futures and option contracts totaled 11.2 million dekatherms and 9.7 million dekatherms, respectively. At December 31, 2014, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 9 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. Because we have chosen not to elect the NPNS exception under GAAP related to these derivative instruments, 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). At December 31, 2014 and 2013, the volumes of Electric Utility's forward electricity purchase contracts were 486.2 million kilowatt hours and 324.4 million kilowatt hours, respectively. At December 31, 2014, the maximum period over which these contracts extend is 17 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 December 31, 2014 and 2013, the total volumes associated with FTRs and NYISO capacity contracts totaled 331.8 million kilowatt hours and 1,085.9 million kilowatt hours, respectively. At December 31, 2014, the maximum period over which we are economically hedging electricity congestion and locational basis differences is 5 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, IntercontinentalExchange ("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 income.

At December 31, 2014 and 2013, total volumes associated with Midstream & Marketing's natural gas futures, forward and pipeline contracts totaled 70.0 million dekatherms and 27.4 million dekatherms, respectively. At December 31, 2014, the maximum period over which we are hedging our exposure to the variability in cash flows associated with natural gas commodity price risk is 41 months. At December 31, 2014 and 2013, total volumes associated with Midstream & Marketing's electricity call contracts and electricity put contracts totaled 350.0 million kilowatt hours and 184.1 million kilowatt hours, and 664.7 million kilowatt hours and 371.0 million kilowatt hours, respectively. At December 31, 2014, 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 24 months for electricity call contracts and 9 months for electricity put contracts. At December 31, 2014, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 0.6 million dekatherms and 2.6 million gallons, respectively. At December 31, 2013, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 1.1 million dekatherms and 2.2 million gallons, respectively.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures and swap contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment.

At December 31, 2014, 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.

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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 December 31, 2014 and 2013, the total notional amounts of variable-rate debt subject to interest rate swap agreements (excluding Flaga's cross-currency swap as described below) were €401.1 and €439.8, 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 December 31, 2014 and 2013, we had no unsettled IRPAs.

We account for interest rate swaps and IRPAs as cash flow hedges. At December 31, 2014, 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 $2.7.

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 December 31, 2014 and 2013, we were hedging a total of $225.8 and $149.1 of U.S. dollar-denominated LPG purchases, respectively. At December 31, 2014, 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 36 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 December 31, 2014 and 2013, 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 December 31, 2014, 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 $8.7.

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 December 31, 2014, 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 December 31, 2014 and 2013, restricted cash in brokerage accounts totaled $54.6 and $3.2, 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 December 31, 2014. 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 December 31, 2014, 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 December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013 (a)
Derivative assets:		
Derivatives designated as hedging instruments:		
Commodity contracts	$ —	$ 41.5
Foreign currency contracts	18.7	0.4
Cross-currency contracts	4.3	—
Interest rate contracts	0.1	—
	23.1	41.9
Derivatives subject to utility rate regulation:		
Commodity contracts	0.2	2.0
Derivatives not designated as hedging instruments:		
Commodity contracts	40.0	15.9
Total derivative assets	$ 63.3	$ 59.8
Derivative liabilities:		
Derivatives designated as hedging instruments:		
Commodity contracts	$ —	$ (0.6)
Foreign currency contracts	—	(7.2)
Cross-currency contracts	—	(2.1)
Interest rate contracts	(17.0)	(29.2)
	(17.0)	(39.1)
Derivatives subject to utility rate regulation:		
Commodity contracts	(9.4)	(3.4)
Derivatives not designated as hedging instruments:		
Commodity contracts	(288.5)	(6.7)
Total derivative liabilities	$ (314.9)	$ (49.2)

(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 December 31, 2014 and 2013:

	Gross Amounts Recognized	Gross Amounts Offset in Balance Sheet	Net Amounts Recognized	Cash Collateral (Received) Pledged	Net Amounts Recognized in Balance Sheet
December 31, 2014					
Derivative assets	$ 63.3	$ (27.5)	$ 35.8	$ —	$ 35.8
Derivative liabilities	$ (314.9)	$ 27.5	$ (287.4)	$ 90.5	$ (196.9)
December 31, 2013					
Derivative assets	$ 59.8	$ (6.0)	$ 53.8	$ —	$ 53.8
Derivative liabilities	$ (49.2)	$ 6.0	$ (43.2)	$ —	$ (43.2)

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 months ended December 31, 2014 and 2013:

	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 December 31,	2014	2013	2014	2013	
Cash Flow Hedges:					
Commodity contracts	$ —	$ 53.4	$ (2.4)	$ 22.3	Cost of sales
Foreign currency contracts	8.7	(2.5)	2.7	(2.1)	Cost of sales
Cross-currency contracts	2.1	(1.2)	—	(0.3)	Interest expense
Interest rate contracts	0.8	(1.7)	(3.9)	(4.1)	Interest expense / other operating income, net
Total	$ 11.6	$ 48.0	$ (3.6)	$ 15.8	

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Three Months Ended December 31,	2014	2013	
Derivatives Not Designated as Hedging Instruments:			
Commodity contracts	$ (292.5)	$ 12.8	Cost of sales
Commodity contracts	3.8	—	Revenues
Commodity contracts	(0.5)	0.1	Operating expenses / other operating income, net
Total	$ (289.2)	$ 12.9	

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 months ended December 31, 2014 and 2013.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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 which 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.

Note 12 — Accumulated Other Comprehensive Income

The table below presents changes in AOCI during the three months ended December 31, 2014 and 2013:

Three Months Ended December 31, 2014	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI - September 30, 2014	$ (20.6)	$ (9.3)	$ 8.7	$ (21.2)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	7.7	(30.5)	(22.8)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	1.0	3.6	—	4.6
Reclassification adjustments tax expense	(0.4)	(1.5)	—	(1.9)
Reclassification adjustments (after-tax)	0.6	2.1	—	2.7
Other comprehensive income (loss)	0.6	9.8	(30.5)	(20.1)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	1.2	—	1.2
Other comprehensive income (loss) attributable to UGI	0.6	11.0	(30.5)	(18.9)
AOCI - December 31, 2014	$ (20.0)	$ 1.7	$ (21.8)	$ (40.1)

Three Months Ended December 31, 2013	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)	—	40.5	12.3	52.8
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.3	(15.8)	—	(15.5)
Reclassification adjustments tax benefit	0.1	2.0	—	2.1
Reclassification adjustments (after-tax)	0.4	(13.8)	—	(13.4)
Other comprehensive income	0.4	26.7	12.3	39.4
Deduct other comprehensive income attributable to noncontrolling interests, principally in AmeriGas Partners	—	(15.6)	—	(15.6)
Other comprehensive income attributable to UGI	0.4	11.1	12.3	23.8
AOCI - December 31, 2013	$ (16.0)	$ (15.8)	$ 64.0	$ 32.2

For additional information on amounts reclassified from AOCI relating to derivative instruments, see Note 11.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Note 13 — 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."

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 commodity derivative instruments. 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 December 31, 2014									
Revenues	$ 2,004.6	$ (67.7) (c)	$ 888.8	$ 260.5	$ 297.0	$ 16.5	$ 337.9	$ 224.6	$ 47.0
Cost of sales	$ 1,404.6	$ (67.0) (c)	$ 462.4	$ 127.2	$ 234.4	$ 8.0	$ 209.3	$ 172.6	$ 257.7
Segment profit:									
Operating income (loss)	$ 83.3	$ —	$ 139.7	$ 71.8	$ 46.2	$ (0.7)	$ 38.4	$ 15.1	$ (227.2)
Loss from equity investees	(1.0)	—	—	—	—	—	(1.0)	—	—
Interest expense	(59.0)	—	(41.0)	(10.1)	(0.6)	—	(5.6)	(1.0)	(0.7)
Income (loss) before income taxes	$ 23.3	$ —	$ 98.7	$ 61.7	$ 45.6	$ (0.7)	$ 31.8	$ 14.1	$ (227.9)
Partnership Adjusted EBITDA (a)			$ 188.5						
Noncontrolling interests' net income (loss)	$ (33.9)	$ —	$ 66.8	$ —	$ —	$ —	$ 0.1	$ —	$ (100.8)
Depreciation and amortization	$ 91.0	$ —	$ 49.4	$ 14.3	$ 3.6	$ 2.7	$ 13.3	$ 6.1	$ 1.6
Capital expenditures	$ 123.5	$ —	$ 30.4	$ 53.5	$ 12.8	$ 6.6	$ 12.1	$ 6.4	$ 1.7
As of December 31, 2014									
Total assets	$ 10,430.0	$ (92.7)	$ 4,491.0	$ 2,346.2	$ 699.9	$ 286.4	$ 1,671.5	$ 579.0	$ 448.7
Short-term borrowings	$ 458.5	$ —	$ 253.0	$ 153.5	$ 43.0	$ —	$ —	$ 9.0	$ —
Goodwill	$ 2,806.8	$ —	$ 1,949.6	$ 182.1	$ 5.6	$ —	$ 575.9	$ 87.4	$ 6.2

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
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	Total	Elim-inations	AmeriGas Propane	Gas Utility	Midstream & Marketing: Energy Services	Midstream & Marketing: Electric Generation	UGI International: Antargaz	UGI International: Flaga & Other	Corporate & Other (b)
Three Months Ended December 31, 2013									
Revenues	$ 2,315.9	$ (65.5) (c)	$ 1,045.8	$ 271.6	$ 272.7	$ 20.8	$ 425.3	$ 293.3	$ 51.9
Cost of sales	$ 1,429.9	$ (64.4) (c)	$ 582.7	$ 135.5	$ 227.1	$ 10.6	$ 282.5	$ 231.7	$ 24.2
Segment profit:									
Operating income	$ 363.7	$ (0.1)	$ 179.7	$ 82.1	$ 31.8	$ 4.4	$ 43.2	$ 13.7	$ 8.9
Income from equity investees	—	—	—	—	—	—	—	—	—
Interest expense	(59.3)	—	(41.6)	(8.4)	(1.0)	—	(6.4)	(1.3)	(0.6)
Income before income taxes	$ 304.4	$ (0.1)	$ 138.1	$ 73.7	$ 30.8	$ 4.4	$ 36.8	$ 12.4	$ 8.3
Partnership Adjusted EBITDA (a)			$ 230.2						
Noncontrolling interests' net income	$ 95.5	$ —	$ 95.4	$ —	$ —	$ —	$ 0.1	$ —	$ —
Depreciation and amortization	$ 94.0	$ —	$ 52.3	$ 13.4	$ 2.6	$ 2.6	$ 15.0	$ 6.6	$ 1.5
Capital expenditures	$ 102.8	$ (1.2)	$ 23.3	$ 32.9	$ 21.7	$ 9.3	$ 9.8	$ 4.6	$ 2.4
As of December 31, 2013									
Total assets	$ 10,663.5	$ (101.1)	$ 4,682.3	$ 2,188.6	$ 574.8	$ 279.3	$ 1,938.9	$ 696.5	$ 404.2
Short-term borrowings	$ 421.5	$ —	$ 208.8	$ 73.5	$ 124.5	$ —	$ —	$ 14.7	$ —
Goodwill	$ 2,884.5	$ —	$ 1,938.8	$ 182.1	$ 2.8	$ —	$ 654.3	$ 99.5	$ 7.0

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

Three Months Ended December 31,	2014	2013
Partnership Adjusted EBITDA	$ 188.5	$ 230.2
Depreciation and amortization	(49.4)	(52.3)
Noncontrolling interests (i)	0.6	1.8
Operating income	$ 139.7	$ 179.7

(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 $(229.7) and $(7.2) during the three months ended December 31, 2014 and 2013, respectively. Corporate & Other assets principally comprise cash, short-term investments, the assets of Electric Utility and HVAC, and, in the three months ended December 31, 2013, an intercompany loan. The intercompany loan and associated interest is removed in the segment presentation.

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

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 December 31, 2014 ("2014 three-month period") with the three months ended December 31, 2013 ("2013 three-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 13 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 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 associated with transactions forecasted to occur in a future period.

Executive Overview

We recorded GAAP net income attributable to UGI Corporation for the 2014 three-month period of $34.1 million, equal to $0.19 per diluted share, compared to GAAP net income attributable to UGI Corporation for the 2013 three-month period of $122.0 million, equal to $0.70 per diluted share. Adjusted net income attributable to UGI (which excludes the effects of gains and losses on commodity derivative instruments not associated with current period transactions and, with respect to the 2013 three-month period, the retroactive impact of a change in tax laws in France) was $116.0 million (equal to $0.66 per diluted share) in the 2014 three-month period compared to $123.5 million (equal to $0.71 per diluted share) in the 2013 three-month period. 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. For further information on these non-GAAP measures including reconciliations to their most directly comparable GAAP measures, see “Non-GAAP Financial Measures - Adjusted Net Income Attributable to UGI and Adjusted Earnings Per Diluted Share” below.

The $87.9 million decrease in GAAP net income attributable to UGI during the 2014 three-month period reflects the effects of after-tax losses on commodity derivative instruments not associated with current-period transactions totaling $81.9 million (equal to $0.47 per diluted share) compared to after-tax gains of $4.2 million (equal to $0.02 per diluted share) in the 2013 three-month period. The $81.9 million of after-tax losses on commodity derivative instruments not associated with current-period transactions recorded in the 2014 three-month period reflect the effects on our unsettled commodity derivative instruments of substantial declines in worldwide energy commodity prices. After-tax gains and losses on commodity derivative instruments are included in “Corporate & Other” in our business unit summary table below. GAAP net income attributable to UGI in the 2013 three-month period also reflects the retroactive effect to Fiscal 2013 of a change in tax laws in France, which increased 2013 three-month period tax expense, and reduced 2013 three-month period GAAP net income attributable to UGI, by $5.7 million or $0.03 per diluted share.

The $7.5 million decrease in adjusted net income attributable to UGI in the 2014 three-month period includes a $6.6 million decrease in net income attributable to UGI from AmeriGas Propane and a $6.5 million decline in net income from Gas Utility. These decreases were partially offset by a $4.3 million increase in net income from Midstream & Marketing. The increase in Midstream & Marketing results principally reflects greater margin from capacity management and peaking activities and, to a lesser extent, natural gas gathering activities. The lower Gas Utility and AmeriGas Propane results principally reflect the effects on volumes sold from weather that was warmer than normal and warmer than in the prior-year three-month period. UGI International net income attributable to UGI during the 2014 three-month period was $32.2 million, a decline of $0.9 million from the $33.1 million in net income recorded in the 2013 three-month period (excluding the effects of the $5.7 million French tax law adjustment). Although the euro and, to a much lesser extent, the British pound sterling were weaker during the 2014 three-month period, the effects of the weaker currencies did not have a material impact on UGI International’s net income. UGI International average temperatures during the 2014 three-month period were substantially warmer than normal and warmer than the prior-year three-month period. Although the warmer weather reduced UGI International LPG retail volumes sold, the effects of higher average retail unit margins at Antargaz, lower total UGI International operating and administrative expenses and higher other operating income offset much of the decline in total margin that resulted from the lower retail sales.

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 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 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:

	Three Months Ended December 31,	
(Millions of dollars, except per share amounts)	2014	2013
Adjusted net income attributable to UGI Corporation:		
Net income attributable to UGI Corporation	$ 34.1	$ 122.0
Net after-tax losses (gains) on commodity derivative instruments not associated with current period transactions (a)	81.9	(4.2)
Retroactive impact of change in French tax law	—	5.7
Adjusted net income attributable to UGI Corporation	$ 116.0	$ 123.5
Adjusted diluted earnings per share:		
UGI Corporation earnings per share - diluted	$ 0.19	$ 0.70
Net after-tax losses (gains) on commodity derivative instruments not associated with current period transactions	0.47	(0.02)
Retroactive impact of change in French tax law	—	0.03
Adjusted diluted earnings per share	$ 0.66	$ 0.71

(a) Income taxes associated with pre-tax adjustments determined using statutory business unit tax rates.

RESULTS OF OPERATIONS

2014 three-month period compared to the 2013 three-month period

Net Income Attributable to UGI Corporation by Business Unit

For the three months ended December 31,	2014		2013		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane	$ 18.9	55.4 %	$ 25.5	20.9%	$ (6.6)	(25.9)%
UGI International (a)	32.2	94.4 %	27.4	22.5%	4.8	17.5 %
Gas Utility	36.9	108.2 %	43.4	35.6%	(6.5)	(15.0)%
Midstream & Marketing	26.3	77.1 %	22.0	18.0%	4.3	19.5 %
Corporate & Other (b)	(80.2)	(235.2)%	3.7	3.0%	(83.9)	N.M.
Net income attributable to UGI Corporation	$ 34.1	100.0 %	$ 122.0	100.0%	$ (87.9)	(72.0)%

(a) Three months ended December 31, 2013 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) gains on commodity derivative instruments not associated with current-period transactions of $(81.9) million and $4.2 million for the three months ended December 31, 2014 and 2013, respectively.
N.M. — Variance is not meaningful.

AmeriGas Propane

For the three months ended December 31,	2014	2013	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 888.8	$ 1,045.8	$ (157.0)	(15.0)%
Total margin (a)	$ 426.4	463.1	$ (36.7)	(7.9)%
Operating and administrative expenses	$ 247.4	$ 237.6	$ 9.8	4.1 %
Partnership Adjusted EBITDA (b)	$ 188.5	$ 230.2	$ (41.7)	(18.1)%
Operating income (b)	$ 139.7	$ 179.7	$ (40.0)	(22.3)%
Retail gallons sold (millions)	340.2	374.1	(33.9)	(9.1)%
Degree days—% (warmer) colder than normal (c)	(6.2)%	3.8%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended December 31, 2014 excludes net pre-tax losses of $138.2 million on AmeriGas Propane unsettled commodity derivative instruments not associated with current-period transactions.

(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 13 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 2014 three-month period decreased 9.1% compared with the prior-year period. The decline in retail gallons sold in the 2014 three-month period principally reflects average temperatures based upon heating degree days that were 6.2% warmer than normal and 9.6% warmer than the prior year.

Retail propane revenues decreased $120.4 million during the 2014 three-month period reflecting the effects of lower retail volumes sold ($83.2 million) and lower average retail selling prices ($37.2 million), principally the result of the lower propane product costs. Wholesale propane revenues decreased $37.2 million during the 2014 three-month period reflecting the effects of lower wholesale volumes sold ($32.5 million) and lower wholesale selling prices ($4.7 million). Average daily wholesale propane commodity prices during the 2014 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 36% lower than such prices during the 2013 three-month period. Revenues from fee income and other ancillary sales and services in the 2014 three-month period were about equal to such revenues in the prior-year period. Total cost of sales during the 2014 three-month period decreased $120.3 million principally reflecting the effects of the lower retail and wholesale volumes sold ($77.7 million) and the lower average propane product costs ($44.4 million) partially offset by higher cost of sales from ancillary sales and services.

Total margin decreased $36.7 million in the 2014 three-month period principally reflecting lower retail propane total margin ($34.2 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.

Partnership Adjusted EBITDA in the 2014 three-month period decreased $41.7 million principally reflecting the lower retail propane total margin ($34.2 million) and slightly higher operating and administrative expenses ($9.8 million) partially offset by slightly higher other operating income, principally from sales of excess assets.The increase in operating and administrative expenses reflects, among other things, higher casualty and general liability expenses and, to a lesser extent, higher professional fees partially offset by lower vehicle operating and maintenance expenses. Operating income decreased $40.0 million in the 2014 three-month period principally reflecting the lower Partnership Adjusted EBITDA ($41.7 million) partially offset by slightly lower depreciation expense.

UGI International

For the three months ended December 31,	2014	2013	Decrease	
(Dollars in millions)				
Revenues	$ 562.5	$ 718.6	$ (156.1)	(21.7)%
Total margin (a)	$ 180.6	$ 204.4	$ (23.8)	(11.6)%
Operating and administrative expenses	$ 111.2	$ 126.6	$ (15.4)	(12.2)%
Operating income	$ 53.5	$ 56.9	$ (3.4)	(6.0)%
Income before income taxes	$ 45.9	$ 49.2	$ (3.3)	(6.7)%
Retail gallons sold (millions) (b)	179.8	194.3	(14.5)	(7.5)%
Antargaz degree days—% (warmer) than normal (c)	(20.2)%	(7.2)%	—	—
Flaga degree days—% (warmer) than normal (c)	(17.4)%	(12.9)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended December 31, 2014 excludes net pre-tax losses of $46.0 million on UGI International's unsettled 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.

Based upon heating degree day data, temperatures during the 2014 three-month period in our UGI International European LPG territories were significantly warmer than normal and warmer than in the 2013 three-month period. Total retail gallons sold during the 2014 three-month period were lower principally reflecting the effects of the warmer 2014 three-month period weather on heating-related sales. During the 2014 three-month period, average wholesale commodity prices for propane and butane in northwest Europe were each nearly 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 2014 three-month period and the 2013 three-month period, the average un-weighted euro-to-dollar translation rate was approximately $1.24 and $1.36, respectively. 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 effect on UGI International net income.

UGI International revenues decreased $156.1 million during the 2014 three-month period principally reflecting lower average LPG selling prices at each of our European LPG businesses, principally the result of the previously mentioned significant decline in commodity LPG prices; the combined impact on revenues of the weaker euro and, to a lesser extent, the British pound sterling ($47.6 million); and the lower retail gallons sold. These decreases in revenues were partially offset by higher natural gas marketing revenues at Antargaz ($20.4 million). UGI International cost of sales decreased $132.3 million during the 2014 three-month period principally reflecting the effects of the weaker euro and, to a lesser extent, the British pound sterling, lower average retail and wholesale LPG selling prices, and the lower retail gallons sold.

Total UGI International margin decreased $23.8 million during the 2014 three-month period principally reflecting the effects of the weaker euro and, to a lesser extent, the British pound sterling as well as a decline in local currency LPG total margin. The lower local currency LPG total margin principally reflects the effects of lower Antargaz and Flaga retail LPG volumes sold partially offset by higher Antargaz retail unit margins. The decline in LPG total margin was partially offset by an increase in margin from natural gas marketing activities at Antargaz ($3.8 million).

UGI International operating income and income before income taxes during the 2014 three-month period decreased $3.4 million and $3.3 million, respectively, principally reflecting the effects of the weaker euro and British pound sterling. Local currency operating income and income before income taxes at each of our UGI International European business units were slightly higher than in the prior-year period as lower local currency total margin was offset by lower UGI International operating and administrative costs and higher other operating income at Flaga. In U.S. dollars, the decreases in operating income and income before income taxes principally reflect the lower total margin ($23.8 million) offset in large part by lower operating and administrative expenses ($15.4 million) and slightly higher other operating income. UGI International operating and administrative expenses in the 2014 three-month period also include approximately $3.0 million of incremental expenses associated with the proposed acquisition of Total's retail LPG distribution business in France by UGI's indirect wholly owned French subsidiary, UGI Bordeaux Holding.

Gas Utility

For the three months ended December 31,		2014		2013		Increase (Decrease)	
(Dollars in millions)							
Revenues	$	260.5	$	271.6	$	(11.1)	(4.1)%
Total margin (a)	$	133.3	$	136.1	$	(2.8)	(2.1)%
Operating and administrative expenses	$	45.0	$	38.6	$	6.4	16.6 %
Operating income	$	71.8	$	82.1	$	(10.3)	(12.5)%
Income before income taxes	$	61.7		73.7	$	(12.0)	(16.3)%
System throughput—billions of cubic feet (“bcf”) —							
Core market		23.2		24.1		(0.9)	(3.7)%
Total		56.8		56.7		0.1	0.2 %
Degree days—% (warmer) colder than normal (b)		(3.9)%		3.0%		—	—

(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 2014 three-month period based upon heating degree days were 3.9% warmer than normal and 6.8% warmer than the 2013 three-month period. Although core market throughput was slightly lower than the prior-year period from the warmer weather, total distribution system throughput in the 2014 three-month period was about equal with the prior-year period principally reflecting slightly higher large firm delivery service volumes and 1.9% year-over-year growth 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 $11.1 million during the 2014 three-month period principally reflecting lower revenues from core market customers ($8.0 million) and lower revenues from off-system sales ($2.9 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 2014 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 $127.2 million in the 2014 three-month period compared with $135.5 million in the 2013 three-month period principally reflecting the effects of the lower retail core-market volumes sold ($4.8 million) and the lower off-system sales ($2.9 million).

Gas Utility 2014 three-month period total margin decreased $2.8 million principally reflecting lower core market total margin ($2.9 million). The lower core market total margin reflects the effects of the previously mentioned warmer weather on heating related sales partially offset by customer growth.

Gas Utility operating income and income before income taxes during the 2014 three-month period decreased $10.3 million and $12.0 million, respectively, over the 2013 three-month period. The decrease in Gas Utility operating income principally reflects the $2.8 million decrease in total margin and higher operating, administrative and depreciation expenses. These expenses were modestly higher than the prior year principally reflecting, among other things, higher 2014 three-month period distribution system maintenance expenses ($2.9 million), higher depreciation expense ($0.9 million) and higher employee benefit and information technology expenses. The decrease in Gas Utility income before income taxes reflects the lower operating income ($10.3 million) and higher interest expense.

Midstream & Marketing

For the three months ended December 31,		2014		2013		Increase	
(Dollars in millions)							
Revenues (a)	$	309.2	$	289.0	$	20.2	7.0%
Total margin (b)	$	71.1	$	55.8	$	15.3	27.4%
Operating and administrative expenses	$	19.3	$	14.2	$	5.1	35.9%
Operating income	$	45.5	$	36.2	$	9.3	25.7%
Income before income taxes	$	44.9	$	35.2	$	9.7	27.6%

(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 (losses) gains from changes in the fair values of Midstream & Marketing's unsettled commodity derivative instruments and pre-tax (losses) gains on certain settled commodity derivative instruments not associated with current period transactions of $(45.5) million and $7.2 million during the 2014 three-month period and the 2013 three-month period, respectively.

Midstream & Marketing 2014 three-month period total revenues were $20.2 million higher than the 2013 three-month period principally reflecting higher natural gas revenues ($18.6 million) and higher capacity management revenues ($13.1 million) partially offset by lower retail power and Electric Generation revenues ($13.9 million).The increase in natural gas revenues principally reflects higher wholesale and retail natural gas volumes sold during the 2014 three-month period. The greater capacity management revenues principally reflect higher year-over-year prices for pipeline capacity resulting from higher locational basis differences due to greater volatility in capacity values between Marcellus and non-Marcellus delivery points. The lower 2014 three-month period retail power revenues reflect lower sales volumes while the decline in Electric Generation revenue principally reflects the effects of scheduled maintenance outages at the Hunlock Station and Conemaugh generating units. Midstream & Marketing cost of sales increased slightly to $238.1 million in the 2014 three-month period compared to $233.2 million in the 2013 three-month period principally reflecting higher natural gas cost of sales ($21.0 million) on the higher natural gas volumes partially offset principally by lower retail power and Electric Generation cost of sales.

Midstream & Marketing total margin increased $15.3 million in the 2014 three-month period principally reflecting higher capacity management and peaking service total margin ($15.4 million) and, to a lesser extent, higher natural gas gathering and natural gas storage total margin. The greater capacity management revenues principally reflect higher year-over-year prices for pipeline capacity resulting from higher locational basis differences due to greater volatility in capacity values between Marcellus and non-Marcellus delivery points. These increases were partially offset by lower total margin from Electric Generation principally reflecting the impact of scheduled outages on sales partially offset by higher unit margins at the Hunlock Station.

Midstream & Marketing operating income and income before income taxes during the 2014 three-month period increased $9.3 million and $9.7 million, respectively, principally reflecting the previously mentioned increase in total margin ($15.3 million), partially offset by higher operating and administrative expenses ($5.1 million) and higher depreciation expenses ($1.1 million). 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 and higher operating costs associated with our expanded natural gas gathering assets including the impact of the Auburn pipeline extension. Depreciation expense was greater in the 2014 three-month period reflecting incremental depreciation expense associated with storage and natural gas gathering assets.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2014 three-month period was $59.0 million, approximately equal to the $59.3 million of interest expense recorded during the 2013 three-month period. Our effective income tax rate (excluding the effects on such rate of pretax income associated with noncontrolling interests not subject to federal income taxes) in the 2014 three-month period was slightly lower than such rate calculated in the prior-year three-month period as the prior year 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 $410.1 million at December 31, 2014, compared with $419.5 million at September 30, 2014. Excluding cash and cash equivalents that reside at UGI's operating subsidiaries, at December 31, 2014 and September 30, 2014, UGI had $245.9 million of cash and cash equivalents. Such cash is available to pay dividends on UGI Common Stock and for investment purposes.

Long-term Debt and Credit Facilities

The Company's debt outstanding at December 31, 2014, totaled $3,946.8 million (including current maturities of long-term debt of $147.1 million and short-term borrowings of $458.5 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 December 31, 2014, consists of (1) $2,544.7 million of Partnership debt; (2) $551.6 million of UGI International debt; (3) $795.5 million of UGI Utilities debt; (4) $43.9 million of Energy Services debt; and (5) $11.1 million of other debt.

AmeriGas Partners. AmeriGas Partners' total debt at December 31, 2014, includes $2,250.8 million of AmeriGas Partners' Senior Notes, $253.0 million of AmeriGas OLP short-term borrowings and $40.9 million of other long-term debt.

UGI International. UGI International's total debt at December 31, 2014, includes $413.8 million (€342 million) outstanding under Antargaz' Senior Facilities term loan, $52 million under Flaga's U.S. dollar-denominated term loan and a combined $71.5 million (€59.1 million) outstanding under Flaga's euro-denominated term loans. Total UGI International debt outstanding at December 31, 2014, also includes $9.0 million (€7.4 million) of Flaga short-term borrowings and $5.3 million (€4.4 million) of other long-term debt.

UGI Utilities. UGI Utilities' total debt at December 31, 2014, includes $450.0 million of Senior Notes, $192.0 million of Medium-Term Notes and $153.5 million of short-term borrowings. UGI Utilities has a $300 million Credit Agreement with a group of banks that is currently scheduled to expire in October 2015. We expect to renew the UGI Utilities Credit Agreement prior to its expiration.

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 for the three months ended December 31, 2014.

UGI International. During the 2014 three-month period, Flaga extended its 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") through September 2015.

Information about the Company's principal credit agreements (excluding the Energy Services Receivables Facility discussed below) as of December 31, 2014 and 2013, is presented in the table below.

(Millions of dollars or euros)	Total Capacity	Borrowings Outstanding	Letters of Credit and Guarantees Outstanding	Available Capacity
As of December 31, 2014				
AmeriGas Credit Agreement	$525.0	$253.0	$64.7	$207.3
Antargaz Credit Facility	€40.0	€0.0	€0.0	€40.0
Flaga Credit Agreements	€58.0	€3.2	€28.4	€26.4
UGI Utilities Credit Agreement	$300.0	$153.5	$2.0	$144.5
Energy Services Credit Agreement	$240.0	$0.0	$0.0	$240.0
As of December 31, 2013				
AmeriGas Credit Agreement	$525.0	$208.8	$64.7	$251.5
Antargaz Credit Facility	€40.0	€0.0	€0.0	€40.0
Flaga Credit Agreements	€58.0	€6.6	€32.5	€18.9
UGI Utilities Credit Agreement	$300.0	$73.5	$2.0	$224.5
Energy Services Credit Agreement	$240.0	$89.0	$0.0	$151.0

The average daily and peak short-term borrowings under the Company's principal credit agreements during the three months ended December 31, 2014 and 2013 are as follows:

	For the three months ended December 31, 2014		For the three months ended December 31, 2013	
(Millions of dollars or euros)	Average	Peak	Average	Peak
AmeriGas Credit Agreement	$177.6	$291.0	$172.1	$266.0
Antargaz Credit Facility	N.A.	N.A.	N.A.	N.A.
Flaga Credit Agreements	€2.4	€3.2	€0.5	€3.6
UGI Utilities Credit Agreement	$115.7	$163.6	$53.0	$84.0
Energy Services Credit Agreement	$0.6	$7.0	$75.6	$89.0

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 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.

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 December 31, 2014, the outstanding balance of ESFC trade receivables was $96.5 million and there was $43.0 million that was sold to the bank and reflected as short-term borrowings on the Condensed Consolidated Balance Sheets. At December 31, 2013, the outstanding balance of ESFC trade receivables was $88.5 million and there was $35.5 million that was sold to the bank.

During the three months ended December 31, 2014 and 2013, Energy Services transferred trade receivables to ESFC totaling $286.4 million and $269.0 million, respectively. During the three months ended December 31, 2014 and 2013, ESFC sold an aggregate $105.0 million and $92.0 million, respectively, of undivided interests in its trade receivables to the bank. During the three months ended December 31, 2014 and 2013, peak sales of receivables were $51.0 million and $42.5 million, respectively, and average daily amounts sold were $18.9 million and $25.8 million, respectively.

Dividends and Distributions

On November 21, 2014, UGI's Board of Directors declared a cash dividend equal to $0.2175 per common share. The dividend was paid on January 1, 2015, to shareholders of record as of December 15, 2014. On January 29, 2015, UGI's Board of Directors declared a quarterly dividend of $0.2175 per common share. The dividend is payable April 1, 2015, to shareholders of record as of March 16, 2015.

During the three months ended December 31, 2014, the General Partner's Board of Directors declared and the Partnership paid a quarterly distribution on all limited partner units at a rate of $0.88 per Common Unit for the quarter ended September 30, 2014. On January 28, 2015, the General Partner's Board of Directors approved a quarterly distribution of $0.88 per limited partner unit for the quarter ended December 31, 2014. The distribution will be paid on February 18, 2015, to unitholders of record on February 10, 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 $19.0 million in the 2014 three-month period compared to cash flow provided by operating activities of $72.9 million in the 2013 three-month period. Cash flow from operating activities before changes in operating working capital was $267.2 million in the 2014 three-month period comparable to the $296.3 million in the prior-year three-month period. Cash required to fund changes in operating working capital totaled $248.2 million in the 2014 three-month period compared to $223.4 million in the prior-year three-month period. Included in changes in operating working capital in the 2014 three-month period are collateral deposits with commodity derivative instrument counterparties of $90.9 million. The collateral deposits required by our derivative instrument counterparties result from the substantial decline in LPG and, to a lesser extent, natural gas commodity prices on our derivative instrument liabilities principally at AmeriGas Propane ($73.6 million) and, to a lesser extent, at UGI International.

Investing Activities. Cash flow used by investing activities was $170.3 million in the 2014 three-month period compared with $148.8 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 payments for property, plant and equipment was $132.1 million in the 2014 three-month period compared to $133.1 million in the prior-year three-month period. The significant increase in restricted cash during the 2014 three-month period reflects the impact of the previously mentioned decline in commodity prices on margin requirements in our NYMEX brokerage accounts.

Financing Activities. Cash flow provided by financing activities was $149.8 million in the 2014 three-month period compared with $101.1 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. The increase in cash provided by financing activities principally reflects higher short-term borrowings and borrowings under Energy Services Receivables Facility to fund, in large part, the previously mentioned cash collateral deposits and margin requirements in our NYMEX brokerage accounts.

Pending Acquisition of Total LPG Distribution Business in France

On November 11, 2014, UGI Corporation's indirect wholly owned subsidiary, UGI Bordeaux Holding, entered into a Share Purchase Agreement with Total Marketing Services, a subsidiary of Total, to acquire all of the outstanding shares of Totalgaz, Total's LPG distribution business in France, for a purchase price between €400 and €450 million in cash, subject to working capital and other adjustments. Totalgaz distributed over 265 million retail gallons of LPG in 2013, serving residential, commercial, industrial and autogas customers. The transaction is subject to customary closing conditions, including regulatory approvals, and is expected to close during the first half of calendar year 2015. UGI expects to fund the purchase of Totalgaz with a combination of long-term debt and cash on the balance sheet.

UGI Corporation's indirect wholly owned subsidiary, UGI International Enterprises, Inc. ("International Enterprises"), has a €300 million Senior Secured Bridge Facility Agreement, as amended, with a consortium of lenders ("Bridge Facility") to provide an additional source of financing, if necessary, to fund a portion of the pending acquisition of Totalgaz. The availability of the Bridge

Facility, which has not yet been drawn, is subject to compliance with certain terms and conditions as set forth in the Bridge Facility, including, among others, the substantially concurrent consummation of the Totalgaz acquisition. Any loans under the Bridge Facility will mature on the date that is one year following the closing date of the acquisition of Totalgaz or if not paid in full will be converted into a term loan maturing on the seventh anniversary of such closing date. The Bridge Facility will be secured on a first-priority basis by certain assets of International Enterprises' subsidiaries and, if drawn, will be guaranteed on a senior unsecured basis by UGI Corporation.

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 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 December 31, 2014, the fair values of Gas Utility's natural gas futures and option contracts were net losses of $6.8 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 December 31, 2014, the fair values of Electric Utility's electricity supply contracts were net losses of $2.4 million. At December 31, 2014, the fair values of Electric Utility's FTRs were not material.

In addition, Gas Utility and Electric Utility from time to time enter into exchange-traded gasoline futures and swap contracts for a portion of gasoline volumes expected to be used in their operations. These gasoline futures and swap contracts are recorded at fair value with changes in fair value reflected in net income.

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 December 31, 2014 (excluding those Gas Utility and Electric Utility commodity derivative instruments that are refundable to or recoverable from customers) was a loss of $248.5 million. A hypothetical 10.0% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would increase such loss by approximately $50.0 million at December 31, 2014.

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 December 31, 2014, 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 December 31, 2014, combined borrowings outstanding under these variable-rate debt agreements, excluding Antargaz' and Flaga's effectively fixed-rate debt, totaled $458.5 million.

The fair value of unsettled interest rate risk sensitive derivative instruments held at December 31, 2014 (including pay-fixed, receive-variable interest rate swaps) was a loss of $16.9 million. A 50 basis point adverse change in the three-month euribor rate would result in a decrease in fair value of approximately $3.0 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 December 31, 2014, there were no unsettled net investment hedges outstanding. With respect to our net investments in our International Propane 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 December 31, 2014, by approximately $90.0 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 December 31, 2014, was a gain of $23.0 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 $26.0 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 December 31, 2014 and 2013, restricted cash in brokerage accounts totaled $54.6 million and $3.2 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 December 31, 2014. 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 December 31, 2014, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

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

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.

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**
10.1	Letter of Amendment dated as of January 30, 2015 to Senior Secured Bridge Facility Agreement dated as of October 17, 2014 by and between UGI International Enterprises, Inc., as borrower, Credit Suisse AG, London Branch, Bank of America Merrill Lynch International Limited and Natixis, New York Branch, as mandated lead arrangers, and Credit Suisse AG, Cayman Island Branch, as agent and security agent.	UGI	Form 8-K (1/30/2015)	10.1
31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended December 31, 2014, 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 December 31, 2014, 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 December 31, 2014, 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			

UGI CORPORATION AND SUBSIDIARIES

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: February 6, 2015	By:	/s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: February 6, 2015	By:	/s/ Davinder S. Athwal Davinder S. Athwal Vice President - Accounting and Financial Control and Chief Risk Officer

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UGI CORPORATION AND SUBSIDIARIES

EXHIBIT INDEX

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EXHIBIT 31.1

CERTIFICATION

I, John L. Walsh, certify that:

1. I have reviewed this periodic report on Form 10-Q of UGI Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2015

/s/ John L. Walsh

John L. Walsh
President and Chief Executive Officer of
UGI Corporation

EXHIBIT 31.2

CERTIFICATION

I, Kirk R. Oliver, certify that:

1. I have reviewed this periodic report on Form 10-Q of UGI Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2015

/s/ Kirk R. Oliver

Kirk R. Oliver

Chief Financial Officer of UGI Corporation

EXHIBIT 32

Certification by the Chief Executive Officer and Chief Financial Officer
Relating to a Periodic Report Containing Financial Statements

I, John L. Walsh, Chief Executive Officer, and I, Kirk R. Oliver, Chief Financial Officer, of UGI Corporation, a Pennsylvania corporation (the "Company"), hereby certify that to our knowledge:

(1) The Company's periodic report on Form 10-Q for the period ended December 31, 2014 (the "Form 10-Q") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

CHIEF EXECUTIVE OFFICER	CHIEF FINANCIAL OFFICER
/s/ John L. Walsh	/s/ Kirk R. Oliver
John L. Walsh	Kirk R. Oliver
Date: February 6, 2015	Date: February 6, 2015