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, 2012

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, 2013, there were 113,177,890 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, 2012	September 30, 2012	December 31, 2011
ASSETS			
Current assets:			
Cash and cash equivalents	$ 348.1	$ 319.9	$ 229.0
Restricted cash	6.9	3.0	22.3
Accounts receivable (less allowances for doubtful accounts of $39.9, $36.1 and $38.4, respectively)	999.2	632.6	842.9
Accrued utility revenues	59.0	16.9	53.8
Inventories	378.5	356.9	390.7
Deferred income taxes	57.6	56.8	66.5
Utility regulatory assets	3.6	6.5	8.1
Derivative financial instruments	9.3	13.2	13.4
Prepaid expenses and other current assets	57.5	98.7	41.3
Total current assets	1,919.7	1,504.5	1,668.0
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,359.1, $2,286.0 and $2,113.8, respectively)	4,270.8	4,233.1	3,273.8
Goodwill	2,835.0	2,818.3	1,624.7
Intangible assets, net	646.8	658.2	159.7
Other assets	495.2	495.6	427.7
Total assets	$ 10,167.5	$ 9,709.7	$ 7,153.9
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 164.4	$ 166.7	$ 46.8
Bank loans	333.2	165.1	421.9
Accounts payable	580.7	411.3	507.4
Derivative financial instruments	88.1	100.9	77.1
Other current liabilities	616.8	643.0	511.6
Total current liabilities	1,783.2	1,487.0	1,564.8
Long-term debt	3,358.4	3,347.6	2,115.7
Deferred income taxes	946.1	935.0	693.6
Deferred investment tax credits	4.5	4.6	4.9
Other noncurrent liabilities	629.8	616.7	575.2
Total liabilities	6,722.0	6,390.9	4,954.2
Commitments and contingencies (note 11)			
Equity:			
UGI Corporation stockholders’ equity:			
UGI Common Stock, without par value (authorized—300,000,000 shares; issued — 115,644,794, 115,624,594 and 115,507,094 shares, respectively)	1,170.0	1,157.7	939.1
Retained earnings	1,238.1	1,166.1	1,143.6
Accumulated other comprehensive loss	(43.7)	(62.0)	(61.8)
Treasury stock, at cost	(29.4)	(28.7)	(26.7)
Total UGI Corporation stockholders’ equity	2,335.0	2,233.1	1,994.2
Noncontrolling interests, principally in AmeriGas Partners	1,110.5	1,085.7	205.5
Total equity	3,445.5	3,318.8	2,199.7
Total liabilities and equity	$ 10,167.5	$ 9,709.7	$ 7,153.9

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011
Revenues	$ 2,023.2	$ 1,688.8
Costs and expenses:		
Cost of sales (excluding depreciation shown below)	1,218.8	1,101.8
Operating and administrative expenses	426.9	342.4
Utility taxes other than income taxes	4.3	4.1
Depreciation	71.8	52.8
Amortization	15.3	7.5
Other income, net	(10.0)	(8.1)
	1,727.1	1,500.5
Operating income	296.1	188.3
Loss from equity investees	—	(0.1)
Interest expense	(60.3)	(36.0)
Income before income taxes	235.8	152.2
Income taxes	(65.1)	(42.1)
Net income	170.7	110.1
Less: net income attributable to noncontrolling interests, principally in AmeriGas Partners	(68.1)	(23.1)
Net income attributable to UGI Corporation	$ 102.6	$ 87.0
Earnings per common share attributable to UGI Corporation stockholders:		
Basic	$ 0.91	$ 0.78
Diluted	$ 0.90	$ 0.77
Average common shares outstanding (thousands):		
Basic	113,136	112,240
Diluted	114,490	113,152
Dividends declared per common share	$ 0.27	$ 0.26

See accompanying notes to condensed consolidated financial statements.

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UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended December 31,	
	2012	2011
Net income	$ 170.7	$ 110.1
Other comprehensive income (loss):		
Net losses on derivative instruments (net of tax of $4.3 and $23.1, respectively)	(9.3)	(41.3)
Reclassifications of net losses on derivative instruments (net of tax of $(6.6) and $(8.0), respectively)	21.8	12.5
Foreign currency adjustments (net of tax of $(4.0) and $6.5, respectively)	16.1	(22.2)
Benefit plans (net of tax of $(0.2) and $(0.1), respectively)	0.3	0.1
Other comprehensive income (loss)	28.9	(50.9)
Comprehensive income	199.6	59.2
Less: comprehensive income attributable to noncontrolling interests, principally in AmeriGas Partners	(78.7)	(16.3)
Comprehensive income attributable to UGI Corporation	$ 120.9	$ 42.9

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,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 170.7	$ 110.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	87.1	60.3
Deferred income taxes, net	1.6	(16.9)
Provision for uncollectible accounts	7.4	5.9
Net change in realized gains and losses deferred as cash flow hedges	1.9	(14.1)
Other, net	(3.8)	8.1
Net change in:		
Accounts receivable and accrued utility revenues	(408.1)	(283.7)
Inventories	(19.3)	(25.3)
Utility deferred fuel costs, net of changes in unsettled derivatives	4.8	1.6
Accounts payable	164.8	63.7
Other current assets	31.2	23.3
Other current liabilities	(7.2)	44.6
Net cash provided (used) by operating activities	31.1	(22.4)
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(91.3)	(87.4)
Acquisitions of businesses, net of cash acquired	—	(152.8)
Increase in restricted cash	(3.9)	(5.1)
Other, net	1.8	1.9
Net cash used by investing activities	(93.4)	(243.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(30.6)	(29.2)
Distributions on AmeriGas Partners Common Units	(55.2)	(24.0)
Issuances of debt	—	25.6
Repayments of debt	(6.3)	(3.1)
Increase in bank loans	134.7	265.0
Receivables Facility net borrowings	33.0	18.9
Issuances of UGI Common Stock	10.6	3.1
Other	1.3	0.4
Net cash provided by financing activities	87.5	256.7
EFFECT OF EXCHANGE RATE CHANGES ON CASH	3.0	(0.4)
Cash and cash equivalents increase (decrease)	$ 28.2	$ (9.5)
Cash and cash equivalents:		
End of period	$ 348.1	$ 229.0
Beginning of period	319.9	238.5
Increase (decrease)	$ 28.2	$ (9.5)

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,	
	2012	2011
Common stock, without par value		
Balance, beginning of period	$ 1,157.7	$ 937.4
Common Stock issued in connection with employee and director plans, net of tax withheld	9.6	1.5
Dividend reinvestment plan	0.5	0.5
Excess tax benefits realized on equity-based compensation	1.3	0.2
Stock-based compensation expense	0.9	(0.5)
Balance, end of period	$ 1,170.0	$ 939.1
Retained earnings		
Balance, beginning of period	$ 1,166.1	$ 1,085.8
Net income attributable to UGI Corporation	102.6	87.0
Cash dividends on Common Stock	(30.6)	(29.2)
Balance, end of period	$ 1,238.1	$ 1,143.6
Accumulated other comprehensive loss		
Balance, beginning of period	$ (62.0)	$ (17.7)
Net losses on derivative instruments, net of tax	(7.4)	(33.5)
Reclassification of net losses on derivative instruments, net of tax	9.3	11.5
Benefit plans, net of tax	0.3	0.1
Foreign currency, net of tax	16.1	(22.2)
Balance, end of period	$ (43.7)	$ (61.8)
Treasury stock		
Balance, beginning of period	$ (28.7)	$ (27.8)
Common Stock issued in connection with employee and director plans, net of tax withheld	7.2	0.8
Dividend reinvestment plan	0.2	0.3
Reacquired common stock - employee and director plans	(8.1)	—
Balance, end of period	$ (29.4)	$ (26.7)
Total UGI Corporation stockholders' equity	$ 2,335.0	$ 1,994.2
Noncontrolling interests		
Balance, beginning of period	$ 1,085.7	$ 213.4
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	68.1	23.1
Net losses on derivative instruments	(1.9)	(7.8)
Reclassification of net losses on derivative instruments	12.5	1.0
Dividends and distributions	(55.2)	(24.0)
Other	1.3	(0.2)
Balance, end of period	$ 1,110.5	$ 205.5
Total equity	$ 3,445.5	$ 2,199.7

See accompanying notes to condensed consolidated financial statements.

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

1. Nature of Operations

UGI Corporation ("UGI") is a holding company that, through subsidiaries and affiliates, distributes 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 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"), a publicly traded limited partnership, and its principal operating subsidiary AmeriGas Propane, L.P. ("AmeriGas OLP") and through AmeriGas OLP's principal operating subsidiary Heritage Operating, L.P. ("HOLP"). AmeriGas OLP and HOLP are collectively referred to herein as the "Operating Partnerships." AmeriGas Partners, AmeriGas OLP and HOLP 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, 2012, the General Partner held a 1% general partner interest and 25.3% limited partner interest in AmeriGas Partners and 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 39,488,173 publicly held Common Units and 29,567,362 Common Units held by a subsidiary of Energy Transfer Partners, L.P. ("ETP") as a result of the January 12, 2012, acquisition of substantially all of ETP's propane operations ("Heritage Propane").

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 "International Propane."

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

Our natural gas and electric distribution utility businesses are 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." UGI Gas, PNG and CPG are collectively referred to as "Gas Utility." 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, and Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as "Utilities."

2. 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 and ETP'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 all significant 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.

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, 2012, 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 our Annual Report on Form 10-K for the year ended September 30, 2012 ("Company's 2012 Annual Financial Statements and Notes"). 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.

Restricted Cash. Restricted cash represents those cash balances in our commodity futures and option brokerage accounts that are restricted from withdrawal.

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,	
	2012	2011
Denominator (thousands of shares):		
Average common shares outstanding for basic computation	113,136	112,240
Incremental shares issuable for stock options and awards	1,354	912
Average common shares outstanding for diluted computation	114,490	113,152

Comprehensive Income. Comprehensive income comprises net income and other comprehensive income (loss). Other comprehensive income (loss) principally comprises (1) gains and losses on derivative instruments qualifying as cash flow hedges, net of reclassifications to net income; (2) actuarial gains and losses on postretirement benefit plans, net of associated amortization; and (3) foreign currency translation and intracompany transaction adjustments.

Income Taxes. During the three months ended December 31, 2011, the Company changed the U.S. tax status of a foreign entity. As a result of the change in tax status, we concluded that it was more likely than not that a portion of our foreign tax credits would be utilized and, accordingly, adjusted our foreign tax credit valuation allowance which reduced income tax expense by $5.5 for the three months ended December 31, 2011.

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.

3. Accounting Changes

New Accounting Standard Not Yet Adopted

Disclosures about Offsetting Assets and Liabilities. In December 2011, the Financial Accounting Standards Board ("FASB") issued new accounting guidance regarding disclosures about offsetting assets and liabilities. The new guidance requires an entity to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on its financial position. The amendments will enhance disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with other GAAP or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in the balance sheet. The new guidance is effective for annual reporting periods beginning on or after January 1, 2013 (Fiscal 2014), and interim periods within those annual periods. We are currently evaluating the impact of the new guidance on our future disclosures.

4. Partnership Acquisition of Heritage Propane

On January 12, 2012, AmeriGas Partners completed the acquisition of Heritage Propane from ETP for total consideration of $2,604.8 comprising $1,472.2 in cash and 29,567,362 AmeriGas Partners Common Units with a fair value of approximately

$1,132.6 (the “Heritage Acquisition”). The Heritage Acquisition was consummated pursuant to a Contribution and Redemption Agreement, dated October 15, 2011, as amended (the “Contribution Agreement”), by and among AmeriGas Partners, ETP, Energy Transfer Partners GP, L.P., the general partner of ETP, and Heritage ETC, L.P. For additional information on the Heritage Acquisition, see Note 4 to the Company’s 2012 Annual Financial Statements and Notes.

The following presents unaudited pro forma income statement and earnings per share data as if the Heritage Acquisition had occurred on October 1, 2011:

	Three Months Ended December 31,	
	2012 (As Reported)	2011 (Pro Forma)
Revenues	$ 2,023.2	$ 2,111.2
Net income attributable to UGI Corporation	$ 102.6	$ 85.4
Earnings per common share attributable to UGI Corporation stockholders:		
Basic	$ 0.91	$ 0.76
Diluted	$ 0.90	$ 0.75

The unaudited pro forma results of operations reflect Heritage Propane’s historical operating results after giving effect to adjustments directly attributable to the transaction that are expected to have a continuing effect. The unaudited pro forma consolidated results of operations are not necessarily indicative of the results that would have occurred had the Heritage Acquisition occurred on the date indicated nor are they necessarily indicative of future operating results.

5. Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	December 31, 2012	September 30, 2012	December 31, 2011
Goodwill (not subject to amortization)	$ 2,835.0	$ 2,818.3	$ 1,624.7
Intangible assets:			
Customer relationships, noncompete agreements and other	$ 694.8	$ 691.9	$ 248.8
Trademarks and tradenames (not subject to amortization)	138.4	137.2	46.4
Gross carrying amount	833.2	829.1	295.2
Accumulated amortization	(186.4)	(170.9)	(135.5)
Intangible assets, net	$ 646.8	$ 658.2	$ 159.7

The changes in goodwill and intangible assets during the three months ended December 31, 2012, principally reflect the effects of currency translation. Amortization expense of intangible assets was $13.3 and $5.8 for the three months ended December 31, 2012 and 2011, respectively. No amortization is included in cost of sales in the Condensed Consolidated Statements of Income. As of December 31, 2012, our expected aggregate amortization expense of intangible assets for the remainder of Fiscal 2013 and for the next four fiscal years is as follows: remainder of Fiscal 2013 — $39.1; Fiscal 2014 — $50.5; Fiscal 2015 — $47.4; Fiscal 2016 — $41.3; Fiscal 2017 — $35.0.

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

6. Segment Information

We have organized our business units into 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 "International Propane" and Energy Services and Electric Generation together as "Midstream & Marketing." For Fiscal 2012, the Company began reporting its Electric Generation operating segment as a separate reportable segment and our former Electric Utility reportable segment was combined with Corporate & Other. Previously, the Electric Generation operating segment was included in the Energy Services' reportable segment. Segment information for the three months ended December 31, 2011 presented below has been adjusted to conform to the current year presentation.

The accounting policies of our reportable segments are the same as those described in Note 2, "Significant Accounting Policies" in the Company's 2012 Annual Financial Statements and Notes. We evaluate AmeriGas Propane's performance principally based upon the Partnership's earnings before interest expense, income taxes, depreciation and amortization ("Partnership EBITDA"). Although we use Partnership 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 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.

UGI CORPORATION AND SUBSIDIARIES

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

Three Months Ended December 31, 2012:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$ 2,023.2	$ (58.5) (c)	$ 876.6	$ 248.3	$ 227.8	$ 14.9	$ 419.3	$ 245.6	$ 49.2
Cost of sales	$ 1,218.8	$ (57.3) (c)	$ 452.1	$ 123.6	$ 187.9	$ 9.6	$ 279.9	$ 194.9	$ 28.1
Segment profit:									
Operating income	$ 296.1	$ —	$ 139.9	$ 69.8	$ 27.3	$ 0.2	$ 47.5	$ 10.3	$ 1.1
Interest expense	(60.3)	—	(41.2)	(9.6)	(1.0)	—	(6.5)	(1.3)	(0.7)
Income before income taxes	$ 235.8	$ —	$ 98.7	$ 60.2	$ 26.3	$ 0.2	$ 41.0	$ 9.0	$ 0.4
Partnership EBITDA (a)			$ 187.8						
Noncontrolling interests' net income	$ 68.1	$ —	$ 68.0	$ —	$ —	$ —	$ 0.1	$ —	$ —
Depreciation and amortization	$ 87.1	$ —	$ 49.4	$ 12.6	$ 1.6	$ 2.5	$ 14.1	$ 5.5	$ 1.4
Capital expenditures	$ 91.3	$ —	$ 26.5	$ 28.5	$ 13.5	$ 6.8	$ 12.2	$ 2.2	$ 1.6
Total assets (at period end)	$10,167.5	$ (101.5)	$ 4,695.6	$ 2,164.4	$ 396.7	$ 261.2	$ 1,828.2	$ 564.1	$ 358.8
Bank loans (at period end)	$ 333.2	$ —	$ 177.2	$ 73.1	$ 69.0	$ —	$ —	$ 13.9	$ —
Goodwill (at period end)	$ 2,835.0	$ —	$ 1,919.2	$ 182.1	$ 2.8	$ —	$ 628.0	$ 95.9	$ 7.0

UGI CORPORATION AND SUBSIDIARIES

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

Three Months Ended December 31, 2011:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$ 1,688.8	$ (56.0) (c)	$ 683.8	$ 255.0	$ 234.1	$ 7.4	$ 301.6	$ 216.7	$ 46.2
Cost of sales	$ 1,101.8	$ (55.0) (c)	$ 443.8	$ 141.7	$ 196.7	$ 4.8	$ 175.7	$ 168.1	$ 26.0
Segment profit:									
Operating income (loss)	$ 188.3	$ —	$ 60.1	$ 61.2	$ 27.4	$ (3.5)	$ 37.3	$ 4.4	$ 1.4
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(36.0)	—	(16.5)	(10.1)	(1.1)	—	(6.5)	(1.0)	(0.8)
Income (loss) before income taxes	$ 152.2	$ —	$ 43.6	$ 51.1	$ 26.3	$ (3.5)	$ 30.7	$ 3.4	$ 0.6
Partnership EBITDA (a)			$ 83.7						
Noncontrolling interests' net income	$ 23.1	$ —	$ 23.0	$ —	$ —	$ —	$ 0.1	$ —	$ —
Depreciation and amortization	$ 60.3	$ —	$ 24.2	$ 12.1	$ 0.7	$ 2.1	$ 14.1	$ 5.5	$ 1.6
Capital expenditures	$ 88.7	$ —	$ 21.6	$ 21.8	$ 18.6	$ 9.5	$ 11.1	$ 4.8	$ 1.3
Total assets (at period end)	$ 7,153.9	$ (85.4)	$ 1,975.7	$ 2,088.7	$ 406.7	$ 251.6	$ 1,693.7	$ 528.9	$ 294.0
Bank loans (at period end)	$ 421.9	$ —	$ 226.0	$ 57.7	$ 118.2	$ —	$ —	$ 20.0	$ —
Goodwill (at period end)	$ 1,624.7	$ —	$ 696.6	$ 182.1	$ 2.8	$ —	$ 641.9	$ 94.3	$ 7.0

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

Three Months Ended December 31,	2012	2011
Partnership EBITDA	$ 187.8	$ 83.7
Depreciation and amortization	(49.4)	(24.2)
Noncontrolling interests (i)	1.5	0.6
Operating income	$ 139.9	$ 60.1

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

(b) Corporate & Other results principally comprise Electric Utility, UGI Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses (”HVAC/R”), net expenses of UGI's captive general liability insurance company and UGI Corporation's unallocated corporate and general expenses and interest income. Corporate & Other assets principally comprise cash, short-term investments, the assets of Electric Utility and HVAC/R, and an intercompany loan. The intercompany loan and associated interest is removed in the segment presentation.

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

7. Energy Services Accounts Receivable Securitization Facility

Energy Services has a $200 receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in April 2013, although the Receivables Facility may terminate prior to such date due to the termination of commitments of the Receivables Facility back-up purchasers.

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 commercial paper conduit of a major bank. ESFC was created and has been structured to isolate its assets from creditors of Energy Services and its affiliates, including UGI. Energy Services continues to service, administer and collect trade receivables on behalf of the commercial paper issuer and ESFC. Trade receivables sold to the commercial paper conduit remain on the Company's balance sheet; the Company reflects a liability equal to the amount advanced by the commercial paper conduit; and the Company records interest expense on amounts sold to the commercial paper conduit.

During the three months ended December 31, 2012 and 2011, Energy Services transferred trade receivables to ESFC totaling $224.3 and $251.2, respectively. During the three months ended December 31, 2012 and 2011, ESFC sold an aggregate $79.5 and $94.0, respectively, of undivided interests in its trade receivables to the commercial paper conduit. At December 31, 2012, the balance of ESFC receivables was $69.3 and there was $33.0 sold to the commercial paper conduit. At December 31, 2011, the outstanding balance of ESFC receivables was $78.4 and there was $33.2 sold to the commercial paper conduit.

8. 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 8 to the Company's 2012 Annual Financial Statements and Notes. UGI Utilities does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with Gas Utility and Electric Utility are included in our accompanying Condensed Consolidated Balance Sheets:

	December 31, 2012	September 30, 2012	December 31, 2011
Regulatory assets:			
Income taxes recoverable	$ 103.7	$ 103.2	$ 98.7
Underfunded pension and postretirement plans	184.8	188.2	148.7
Environmental costs	17.1	16.8	19.4
Deferred fuel and power costs	7.8	11.6	14.8
Removal costs, net	11.5	12.7	11.9
Other	5.7	5.9	8.0
Total regulatory assets	$ 330.6	$ 338.4	$ 301.5
Regulatory liabilities:			
Postretirement benefits	$ 13.5	$ 13.1	$ 11.8
Environmental overcollections	3.1	2.9	4.7
Deferred fuel and power refunds	1.9	4.4	5.0
State tax benefits—distribution system repairs	7.7	7.4	6.5
Other	0.6	0.5	0.4
Total regulatory liabilities	$ 26.8	$ 28.3	$ 28.4

Deferred fuel and power—costs and refunds. Gas Utility's tariffs 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") rates 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 overcollected costs are classified as a regulatory liability.

Gas Utility uses derivative financial instruments to reduce volatility in the cost of natural gas it purchases for firm- residential, commercial and industrial (“retail core-market”) customers. Realized and unrealized gains or losses on natural gas derivative financial instruments are included in deferred fuel costs or refunds. Unrealized gains (losses) on such contracts at December 31, 2012, September 30, 2012 and December 31, 2011 were $(0.4), $5.3 and $(2.6), respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Because these contracts do not currently qualify for the normal purchases and normal sales exception under GAAP, the fair values of these contracts are required to be recognized on the balance sheet with an associated adjustment to regulatory assets or liabilities in accordance with GAAP related to rate-regulated entities. At December 31, 2012, September 30, 2012, and December 31, 2011, the fair values of Electric Utility’s electricity supply contracts were losses of $8.2, $9.2 and $13.5, respectively, which amounts are reflected in current derivative financial instrument liabilities and other noncurrent liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power costs 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 financial 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 refunds. Unrealized gains or losses on FTRs at December 31, 2012, September 30, 2012, and December 31, 2011, were not material.

Allentown, Pennsylvania Natural Gas Incident. On October 3, 2012, UGI Utilities and the PUC Bureau of Investigation and Enforcement (“PUC Staff”) submitted a Joint Settlement Petition (“Joint Settlement”) to settle all regulatory compliance issues raised in the PUC Staff's formal complaint, issued on June 11, 2012 (“PUC Staff Complaint”), pertaining to a natural gas explosion which occurred on February 9, 2011, in Allentown, Pennsylvania and resulted in five deaths, several personal injuries and significant property damage (the “Incident”). The PUC Commissioners adopted a Joint Motion on January 24, 2013 (the “Joint Motion”) to adopt the Joint Settlement, with certain modifications. In addition to the commitments made by UGI Utilities in the Joint Settlement, the Joint Motion would require UGI Utilities to (i) pay a civil penalty amount that increases the amount provided in the Joint Settlement from $0.4 to $0.5; (ii) conduct a pilot new technology leak detection program in Allentown; and (iii) accept new reporting requirements governing its agreed upon 14-year cast iron and 30-year bare steel pipeline replacement program and distribution integrity management program, but would not require UGI Utilities to concede to having violated any regulation or operating procedure. We anticipate that the PUC Staff will issue in the near future a tentative order that incorporates the terms and conditions of the Joint Settlement, as modified. The provisions of the tentative order will become final and effective unless any party to the Joint Settlement objects to any of the terms and conditions included in the tentative order within five business days from the date of the issuance. The Company does not believe that the cost of complying with the requirements of the Joint Motion will have a material impact on UGI Utilities' consolidated financial position, results of operations or cash flows.

9. Defined Benefit Pension and Other Postretirement Plans

In the U.S., we currently sponsor one 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 (“Pension Plan”). We also provide postretirement health care benefits to certain retirees and postretirement life insurance benefits to nearly all domestic 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,		Three Months Ended December 31,	
	2012	2011	2012	2011
Service cost	$ 2.8	$ 2.1	$ 0.2	$ 0.1
Interest cost	5.9	6.1	0.2	0.2
Expected return on assets	(6.9)	(6.4)	(0.1)	(0.1)
Amortization of:				
Prior service cost (benefit)	—	0.1	(0.1)	(0.1)
Actuarial loss	3.8	2.1	0.1	0.1
Net benefit cost	5.6	4.0	0.3	0.2
Change in associated regulatory liabilities	—	—	0.8	0.8
Net expense	$ 5.6	$ 4.0	$ 1.1	$ 1.0

Pension Plan 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 Pension Plan benefits equal to at least the minimum contribution set forth in applicable employee benefit laws. Based upon current assumptions, the Company estimates that it will be required to contribute approximately $10.0 to the Pension Plan during the remainder of Fiscal 2013. During the three months ended December 31, 2012 and 2011, the Company made contributions to the Pension Plan of $5.7 and $4.1, respectively. UGI Utilities has established a Voluntary Employees' Beneficiary Association ("VEBA") trust to pay UGI Gas' and Electric Utility's postretirement health care and life insurance benefits referred to above by depositing into the VEBA the annual amount of postretirement benefit costs determined under GAAP. The difference between such amounts calculated under GAAP and the amounts included in UGI Gas' and Electric Utility's rates is deferred for future recovery from, or refund to, ratepayers. Amounts contributed to the VEBA by UGI Utilities were not material during the three months ended December 31, 2012 and 2011, nor are they expected to be material for all of Fiscal 2013.

We also sponsor unfunded and non-qualified defined benefit supplemental executive retirement plans. We recorded pre-tax expense associated with these plans of $0.8 and $0.7 for the three months ended December 31, 2012 and 2011, respectively.

10. Debt

On December 18, 2012, Energy Services amended and restated its unsecured credit agreement with a group of banks ("Energy Services Credit Agreement") to, among other things, increase its borrowing capacity and extend its expiration. The Energy Services Credit Agreement provides for borrowings up to $240 (including a $50 sublimit for letters of credit) and expires in June 2016. The Energy Services Credit Agreement also provides an option to increase the borrowing capacity by up to an additional $30, to a total of $270, upon approval from one or more of the banks.

Under the Energy Services Credit Agreement, Energy Services may not pay a dividend unless, after giving effect to such dividend payment, the ratio of Consolidated Total Indebtedness to EBITDA, each as defined in the Energy Services Credit Agreement, does not exceed 2.25 to 1.00. In addition, the Energy Services Credit Agreement requires Energy Services to not exceed a ratio of Consolidated Total Indebtedness, as defined, to Consolidated EBITDA, as defined; a minimum ratio of Consolidated EBITDA to Consolidated Interest Expense, as defined; a maximum ratio of Consolidated Total Indebtedness to Consolidated Total Capitalization, as defined, at any time when Consolidated Total Indebtedness is greater than or equal to $250; and a minimum Consolidated Net Worth, as defined, of $200.

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

11. 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 terminates at the end of 2013. 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, 2012 and 2011, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $15.0 and $17.8, respectively. In accordance with GAAP related to rate-regulated entities, we have recorded associated regulatory assets in equal amounts.

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, 2012, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material.

UGI Utilities has been notified of several sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by it or owned or operated by its former subsidiaries. Such parties are investigating the extent of environmental contamination or performing 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.

Sag Harbor, New York Matter. By letter dated June 24, 2004, KeySpan Energy ("KeySpan") informed UGI Utilities that KeySpan has spent $2.3 and expects to spend another $11 to clean up an MGP site it owns in Sag Harbor, New York. KeySpan believes that UGI Utilities is responsible for approximately 50% of these costs as a result of UGI Utilities' alleged direct ownership and operation of the plant from 1885 to 1902. By letter dated June 6, 2006, KeySpan reported that the New York Department of Environmental Conservation has approved a remedy for the site that is estimated to cost approximately $10. KeySpan has indicated that the cost could be as high as $20. There have been no recent developments in this matter.

Omaha, Nebraska. By letter dated October 20, 2011, the City of Omaha and the Metropolitan Utilities District ("MUD") notified UGI Utilities that they had been requested by the United States Environmental Protection Agency ("EPA") to remediate a former manufactured gas plant site located in Omaha, Nebraska. According to a report prepared on behalf of the EPA identifying potentially responsible parties, a former subsidiary of a UGI Utilities' predecessor is identified as an owner and operator of the site. The City of Omaha and MUD have requested that UGI Utilities participate in the cost of remediation for this site. Because of the preliminary nature of available environmental information, the ultimate amount of expected clean up costs cannot be reasonably estimated. In addition, UGI Utilities believes that it has strong defenses to any claims that may arise relating to the remediation of this site. By letter dated November 10, 2011, the EPA notified UGI Utilities of its investigation of the site in Omaha, Nebraska, and issued an information request to UGI Utilities. UGI Utilities responded to the EPA's information request on January 17, 2012, and is cooperating with its investigation.

AmeriGas Propane

AmeriGas OLP Saranac Lake. By letter dated March 6, 2008, the New York State Department of Environmental Conservation ("DEC") notified AmeriGas OLP that DEC had placed property owned by the Partnership in Saranac Lake, New York, on its Registry of Inactive Hazardous Waste Disposal Sites. A site characterization study performed by DEC disclosed contamination related to former MGP operations on the site. DEC has classified the site as a significant threat to public health or environment with further action required. The Partnership has researched the history of the site and its ownership interest in the site. The Partnership has reviewed the preliminary site characterization study prepared by the DEC, the extent of contamination and the possible existence of other potentially responsible parties. The Partnership communicated the results of its research to DEC in January 2009 and is awaiting a response before doing any additional investigation. Because of the preliminary nature of available environmental information, the ultimate amount of expected clean up costs cannot be reasonably estimated.

Claremont, New Hampshire and Chestertown, Maryland. In connection with the Heritage Acquisition on January 12, 2012, a predecessor of Titan Propane LLC ("Titan LLC"), a former subsidiary acquired in the Heritage Acquisition, is purportedly the beneficial holder of title with respect to two former MGPs discussed below. The Contribution Agreement provides for indemnification from ETP for certain expenses associated with remediation of these sites. By letter dated September 30, 2010, the EPA notified Titan LLC that it may be a potentially responsible party ("PRP") for cleanup costs associated with contamination at a former MGP in Claremont, New Hampshire. In June 2010, the Maryland Attorney General ("MAG") identified Titan LLC as a PRP in connection with contamination at a former MGP in Chestertown, Maryland and requested that Titan LLC participate in characterization and remediation activities. Titan LLC has supplied the EPA and MAG with corporate and bankruptcy information for its predecessors to support its claim that it is not liable for any remediation costs at the sites. Because of the preliminary nature of available environmental information, the ultimate amount of expected clean up costs cannot be reasonably estimated.

Other Matters

AmeriGas Cylinder Investigation. On or about October 21, 2009, the General Partner received a notice that the Offices of the District Attorneys of Santa Clara, Sonoma, Ventura, San Joaquin and Fresno Counties and the City Attorney of San Diego (the "District Attorneys") have commenced an investigation into AmeriGas OLP's cylinder labeling and filling practices in California as a result of the Partnership's decision in 2008 to reduce the volume of propane in cylinders it sells to consumers from 17 pounds to 15 pounds. At that time, the District Attorneys issued an administrative subpoena seeking documents and information relating to those practices. We have responded to the administrative subpoena. On or about July 20, 2011, the General Partner received a second subpoena from the District Attorneys. The subpoena sought additional information and documents regarding AmeriGas OLP's cylinder exchange program and we responded to that subpoena. In connection with this matter, the District Attorneys have alleged potential violations of California's antitrust laws, California's slack-fill law, and California's principal false advertising statute. We believe we have strong defenses to these allegations.

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") is conducting an antitrust and consumer protection investigation into certain practices of the Partnership that relate to the filling of portable propane cylinders. On February 2, 2012, the Partnership received a Civil Investigative Demand from the FTC that requests 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 believes that it will have good defenses to any claims that may result from this investigation. We are not able to assess the financial impact this investigation or any related claims may have on the Partnership.

Purported Class Action Lawsuit. In 2005, Samuel and Brenda Swiger (the "Swigers") filed what purports to be a class action lawsuit in the Circuit Court of Harrison County, West Virginia, against UGI, an insurance subsidiary of UGI, certain officers of UGI and the General Partner, and their insurance carriers and insurance adjusters. In this lawsuit, the Swigers are seeking compensatory and punitive damages on behalf of the putative class for alleged violations of the West Virginia Insurance Unfair Trade Practice Act, negligence, intentional misconduct, and civil conspiracy. The Court has not certified the class and, in

October 2008, stayed the lawsuit pending resolution of a separate, but related, class action lawsuit filed against AmeriGas OLP in Monongalia County, which was settled in Fiscal 2011. We believe we have good defenses to the claims in this action.

BP America Production Company v. Amerigas Propane, L.P. On July 15, 2011, BP America Production Company (“BP”) filed a complaint against AmeriGas OLP in the District Court of Denver County, Colorado, alleging, among other things, breach of contract and breach of the covenant of good faith and fair dealing relating to amounts billed for certain goods and services provided to BP since 2005 (the “Services”). The Services relate to the installation of propane-fueled equipment and appliances, and the supply of propane, to approximately 400 residential customers at the request of and for the account of BP. The complaint seeks an unspecified amount of direct, indirect, consequential, special and compensatory damages, including attorneys’ fees, costs and interest and other appropriate relief. It also seeks an accounting to determine the amount of the alleged overcharges related to the Services. We have substantially completed our investigation of this matter and, based upon the results of that investigation, we believe we have good defenses to the claims set forth in the complaint and the amount of loss will not have a material impact on our results of operations and financial condition.

We cannot predict the final results of any of the environmental or other pending claims or legal actions described above. However, it is reasonably possible that some of them could be resolved unfavorably to us and result in losses in excess of recorded amounts. We are unable to estimate any possible losses in excess of recorded amounts. Although we currently believe, after consultation with counsel, that damages or settlements, if any, recovered by the plaintiffs in such claims or actions will not have a material adverse effect on our financial position, damages or settlements could be material to our operating results or cash flows in future periods depending on the nature and timing of future developments with respect to these matters and the amounts of future operating results and cash flows. In addition to the matters described above, there are other pending claims and legal actions arising in the normal course of our businesses. We believe, after consultation with counsel, the final outcome of such other matters will not have a material effect on our consolidated financial position, results of operations or cash flows.

12. Fair Value Measurements

Derivative Financial Instruments

The following table presents our financial assets and financial liabilities that are measured at fair value on a recurring basis for each of the fair value hierarchy levels, including both current and noncurrent portions, as of December 31, 2012, September 30, 2012 and December 31, 2011:

	Asset (Liability)			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total
December 31, 2012:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$ 0.7	$ 6.5	$ —	$ 7.2
Interest rate contracts	$ —	$ 4.2	$ —	$ 4.2
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$ (9.3)	$ (37.6)	$ —	$ (46.9)
Foreign currency contracts	$ —	$ (2.4)	$ —	$ (2.4)
Interest rate contracts	$ —	$ (71.8)	$ —	$ (71.8)
September 30, 2012:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$ 8.6	$ 4.5	$ —	$ 13.1
Foreign currency contracts	$ —	$ 1.8	$ —	$ 1.8
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$ (7.8)	$ (53.2)	$ —	$ (61.0)
Interest rate contracts	$ —	$ (71.9)	$ —	$ (71.9)
December 31, 2011:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$ 7.4	$ 2.0	$ —	$ 9.4
Foreign currency contracts	$ —	$ 7.0	$ —	$ 7.0
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$ (43.9)	$ (34.6)	$ —	$ (78.5)
Interest rate contracts	$ —	$ (52.4)	$ —	$ (52.4)

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 financial instruments are designated as Level 2. The fair values of certain non-exchange traded commodity derivatives are based upon indicative price quotations available through brokers, industry price publications or recent market transactions and related market indicators. For commodity option contracts not traded on an exchange, we use a Black Scholes option pricing model

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that considers time value and volatility of the underlying commodity. The fair values of interest rate contracts and foreign currency contracts are based upon third-party quotes or indicative values based on recent market transactions. 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, 2012, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,522.8 and $3,840.3, respectively. At December 31, 2011, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $2,162.5 and $2,264.9, 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 financial 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 from trade accounts receivable is limited because we have a large customer base that extends across many different U.S. markets and several foreign countries. For information regarding concentrations of credit risk associated with our derivative financial instruments, see Note 13.

13. Disclosures About 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. Because most of our derivative instruments generally qualify as hedges under GAAP or are subject to regulatory rate recovery mechanisms, we expect that changes in the fair value of derivative instruments used to manage commodity, interest rate or currency exchange rate risk would be substantially offset by gains or losses on the associated anticipated transactions.

Commodity Price Risk

In order to manage market price risk associated with the Partnership's fixed-price programs which permit customers to lock in the prices they pay for propane principally during the months of October through March, the Partnership uses over-the-counter derivative commodity instruments, principally price swap contracts. In addition, the Partnership, certain other domestic business units and our International Propane 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, from time to time, the Partnership enters into price swap agreements to reduce short-term commodity price volatility and to provide market price risk support to some of its wholesale customers which are generally not designated as hedges for accounting purposes.

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, 2012 and 2011, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.0 million dekatherms and 9.1 million dekatherms, respectively. At December 31, 2012, the maximum period over which Gas Utility is 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 in accordance with GAAP related to rate-regulated entities and reflected in cost of sales through the PGC mechanism (see Note 8).

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 these contracts currently do not qualify for the normal purchases and normal sales exception under GAAP, the fair values of these contracts are required to be recognized on the balance sheet. At December 31, 2012 and 2011, the fair values of Electric Utility's forward purchase power agreements comprising losses of $8.2 and $13.5, respectively, are reflected in current derivative financial instrument liabilities and other noncurrent liabilities in the accompanying Condensed Consolidated Balance Sheets. In accordance with GAAP related to rate-regulated entities, Electric Utility has recorded equal and offsetting amounts in regulatory assets. At December 31, 2012 and 2011, the volumes of Electric Utility's forward electricity purchase contracts was 482.3 million kilowatt hours and 816.0 million kilowatt hours, respectively. At December 31, 2012, 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 and by purchases of FTRs at monthly auctions. Midstream & Marketing purchases FTRs to economically hedge electricity transmission congestion costs associated with its fixed-price electricity sales contracts. FTRs are derivative financial instruments that entitle the holder to receive compensation for electricity transmission congestion charges that result when there is insufficient electricity transmission capacity on the electric transmission grid. Because Electric Utility is entitled to fully recover its DS costs, gains and losses on Electric Utility FTRs are recorded in regulatory assets or liabilities in accordance with GAAP related to rate-regulated entities and reflected in cost of sales through the DS recovery mechanism (see Note 8). At December 31, 2012 and 2011, the volumes associated with Electric Utility FTRs totaled 118.2 million kilowatt hours and 130.0 million kilowatt hours, respectively. Midstream & Marketing's FTRs are recorded at fair value with changes in fair value reflected in cost of sales. At December 31, 2012 and 2011, the volumes associated with Midstream & Marketing's FTRs totaled 677.5 million kilowatt hours and 882.1 million kilowatt hours, respectively.

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 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 sale of natural gas or propane. Because the contracts associated with the anticipated sale of stored natural gas or propane do not qualify for hedge accounting treatment, any gains or losses on the derivative contracts are recognized in earnings prior to gains or losses from the sale of the stored gas. At December 31, 2012, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 2.4 million dekatherms and 2.0 million gallons, respectively. At December 31, 2011, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 3.9 million dekatherms and 3.5 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. Associated volumes, fair values and effects on net income were not material for all periods presented.

At December 31, 2012 and 2011, we had the following outstanding derivative commodity instruments volumes that qualify for hedge accounting treatment:

	Volumes	
	December 31,	
Commodity	2012	2011
LPG (millions of gallons)	212.1	125.4
Natural gas (millions of dekatherms)	21.1	28.0
Electricity forward purchase contracts (millions of kilowatt-hours)	1,180.8	1,538.3
Electricity forward sales contracts (millions of kilowatt-hours)	195.3	175.4

At December 31, 2012, the maximum period over which we are hedging our exposure to the variability in cash flows associated with LPG commodity price risk is 23 months with a weighted average of 5 months; the maximum period over which we are hedging our exposure to the variability in cash flows associated with natural gas commodity price risk (excluding Gas Utility) is 41 months with a weighted average of 12 months; and the maximum period over which we are hedging our exposure to the variability in cash flows associated with electricity price risk (excluding Electric Utility) is 33 months for electricity forward purchase contracts, with a weighted average of 9 months, and 12 months for electricity forward sales contracts, with a weighted average of 5 months. At December 31, 2012, the maximum period over which we are economically hedging electricity congestion with FTRs (excluding Electric Utility) is 5 months.

We account for commodity price risk contracts (other than those contracts that are not eligible for hedge accounting and Gas Utility and Electric Utility contracts that are subject to regulatory treatment) as cash flow hedges. Changes in the fair values of contracts qualifying for cash flow hedge accounting are recorded in accumulated other comprehensive income ("AOCI") and, with respect to the Partnership, noncontrolling interests, to the extent effective in offsetting changes in the underlying commodity price risk. When earnings are affected by the hedged commodity, gains or losses are recorded in cost of sales on the Condensed Consolidated Statements of Income. At December 31, 2012, the amount of net losses associated with commodity price risk hedges expected to be reclassified into earnings during the next twelve months based upon current fair values is $42.4.

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 has entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on its variable-rate term loan, and Flaga has entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on its term loans, in each case through the respective scheduled maturity dates. As of December 31, 2012 and 2011, the total notional amount of existing variable-rate debt subject to interest rate swap agreements was €441.2 and €442.6, 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, 2012 and 2011, the total notional amount of unsettled IRPAs was $173. Our current unsettled IRPA contracts hedge forecasted interest payments associated with the issuance of UGI Utilities' long-term debt forecasted to occur in September 2013.

We account for interest rate swaps and IRPAs as cash flow hedges. Changes in the fair values of interest rate swaps and IRPAs are recorded in AOCI and, with respect to the Partnership, noncontrolling interests, to the extent effective in offsetting changes in the underlying interest rate risk, until earnings are affected by the hedged interest expense. At such time, gains and losses are recorded in interest expense. At December 31, 2012, 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 $1.0.

Foreign Currency Exchange Rate Risk

In order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases through the use of forward foreign currency exchange contracts. The amount of dollar-denominated purchases of LPG associated with such contracts generally represents approximately 15% to 30% of estimated dollar-denominated purchases of LPG forecasted to occur during the heating-season months of October through March. At December 31, 2012 and 2011, we were hedging a total of $120.0 and $106.0 of U.S. dollar-denominated LPG purchases, respectively. At December 31, 2012, the maximum period over which we are hedging our exposure to the variability in cash flows associated with dollar-denominated purchases of LPG is 27 months with a weighted average of 12 months. 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, 2012, we had no euro-denominated net investment hedges. At December 31, 2011, we were hedging a total of €14.5 of our euro-denominated net investments. From time to time, the Company may enter into foreign currency exchange transactions to economically hedge the local-currency purchase price of anticipated foreign business acquisitions. These transactions do not qualify for hedge accounting treatment and any changes in fair value are recorded in other income, net.

We account for foreign currency exchange contracts associated with anticipated purchases of U.S. dollar-denominated LPG as cash flow hedges. Changes in the fair values of these foreign currency exchange contracts are recorded in AOCI, to the extent effective in offsetting changes in the underlying currency exchange rate risk, until earnings are affected by the hedged LPG purchase, at which time gains and losses are recorded in cost of sales. At December 31, 2012, 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 $1.1. Gains and losses on net investment hedges are included in AOCI until such foreign operations are liquidated.

Derivative Financial Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative financial instrument counterparties. Our derivative financial 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 and options contracts generally require cash deposits in margin accounts. At December 31, 2012 and 2011, restricted cash in brokerage accounts totaled $6.9 and $22.3, respectively. Although we have concentrations of credit risk associated with derivative financial instruments, the maximum amount of loss, based upon the gross fair values of the derivative financial instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at December 31, 2012. 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, 2012, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

The following table provides information regarding the fair values and balance sheet locations of our derivative assets and liabilities existing as of December 31, 2012 and 2011:

	Derivative Assets			Derivative (Liabilities)		
	Balance Sheet Location	Fair Value December 31, 2012	Fair Value December 31, 2011	Balance Sheet Location	Fair Value December 31, 2012	Fair Value December 31, 2011
Derivatives Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments and Other assets	$ 4.9	$ 1.7	Derivative financial instruments and Other noncurrent liabilities	$ (37.9)	$ (62.4)
Foreign currency contracts	Derivative financial instruments and Other assets	—	7.0	Derivative financial instruments and Other noncurrent liabilities	(2.4)	—
Interest rate contracts	Derivative financial instruments	4.2	—	Derivative financial instruments and Other noncurrent liabilities	(71.8)	(52.4)
Total Derivatives Designated as Hedging Instruments		$ 9.1	$ 8.7		$ (112.1)	$ (114.8)
Derivatives Subject to Utility Rate Regulation:						
Commodity contracts	Derivative financial instruments	$ 0.4	$ —	Derivative financial instruments and Other noncurrent liabilities	$ (9.0)	$ (16.1)
Derivatives Not Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments	$ 1.9	$ 7.7	Derivative financial instruments	$ —	$ —
Total Derivatives		$ 11.4	$ 16.4		$ (121.1)	$ (130.9)

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

The following table provides information on the effects of derivative instruments on the Condensed Consolidated Statements of Income and changes in AOCI and noncontrolling interests for the three months ended December 31, 2012 and 2011:

	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
	2012	2011	2012	2011	
Cash Flow Hedges:					
Commodity contracts	$ (10.8)	$ (57.2)	$ (25.3)	$ (19.5)	Cost of sales
Foreign currency contracts	(3.7)	1.9	0.5	0.9	Cost of sales
Interest rate contracts	1.0	(9.6)	(3.5)	(1.9)	Interest expense / other income, net
Total	$ (13.5)	$ (64.9)	$ (28.3)	$ (20.5)	
Net Investment Hedges:					
Foreign currency contracts	$ —	$ 0.5			

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Derivatives Not Designated as Hedging Instruments:	**2012**	**2011**	
Commodity contracts	$ 1.6	$ 3.1	Cost of sales
Commodity contracts	—	(0.1)	Operating expenses / other income, net
Foreign currency contracts	—	0.5	Other income, net
Total	$ 1.6	$ 3.5	

The amounts of derivative gains or losses representing ineffectiveness were not material for the three months ended December 31, 2012 and 2011.

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 and contracts that provide for the purchase and delivery, or sale, of natural gas, LPG and electricity 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, these contracts qualify for normal purchases and normal sales 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.

14. Inventories

Inventories comprise the following:

	December 31, 2012	September 30, 2012	December 31, 2011
Non-utility LPG and natural gas	$ 265.9	$ 240.7	$ 249.1
Gas Utility natural gas	51.8	57.7	87.7
Materials, supplies and other	60.8	58.5	53.9
Total inventories	$ 378.5	$ 356.9	$ 390.7

At December 31, 2012, UGI Utilities is a party to three storage contract administrative agreements (“SCAAs”), one of which expires in October 2013 and two of which expire in October 2015. Pursuant to these and predecessor 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

Notes to Condensed Consolidated Financial Statements
(unaudited)
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of the SCAAs, and makes payments associated with refilling storage inventories during the term 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), are included in the caption "Gas Utility natural gas" in the table above.

As of December 31, 2012, all of UGI Utilities' SCAAs are with Energy Services. The carrying values of natural gas storage inventories released under SCAAs with non-affiliates at September 30, 2012, and December 31, 2011, comprising 3.8 billion cubic feet ("bcf") and 3.3 bcf of natural gas were $11.4 and $15.7, respectively.

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. Such statements use forward-looking words such as "believe," "plan," "anticipate," "continue," "estimate," "expect," "may," "will," 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 LPG, 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 LPG and the impact of regulatory enforcement activity related thereto, ranging from financial penalties, required reporting or operational measures up to suspension of applicable certificates of public convenience; (13) political, regulatory and economic conditions in the United States and in foreign countries, including 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) the timing of development of 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 our Annual Report on Form 10-K for the fiscal year ended September 30, 2012, 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 our business, financial condition or 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 our results of operations for the three months ended December 31, 2012 ("2012 three-month period") with the three months ended December 31, 2011 ("2011 three-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 6 to the condensed consolidated financial statements.

Executive Overview

Because most of our businesses sell 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 are generally higher in our first and second fiscal quarters.

We recorded net income attributable to UGI Corporation of $102.6 million for the 2012 three-month period compared to net income attributable to UGI Corporation of $87.0 million for the prior-year three-month period which included $5.5 million related to the realization of previously unrecognized foreign tax credits. Operating results were higher at each of our businesses in the 2012 three-month period. Notwithstanding average temperatures that were approximately 9% warmer than normal and only slightly colder than the prior-year period, net income attributable to UGI from AmeriGas Propane increased $6.1 million principally reflecting the effects of the January 2012 Heritage Acquisition. Although temperatures in our Gas Utility and International Propane businesses were also warmer than normal, temperatures were substantially colder than the prior-year period resulting in greater volumes and higher total margin from these businesses. In addition to the effects of the colder weather, Gas Utility results continue to reflect the benefits of year-over-year customer growth principally the result of customer conversions from oil prompted by sustained lower natural gas prices and high oil prices. Our Midstream & Marketing business results benefited in the 2012 three-month period from greater income from its Electric Generation business. The improved results principally reflect the benefits from full operation of our Hunlock electricity generating station in the 2012 three-month period and greater 2012 three-month period operating income from our ownership interest in the Conemaugh electricity generating station.

Our International Propane base-currency results are translated into U.S. dollars based upon exchange rates experienced during each of the reporting periods. The differences in exchange rates during the periods did not have a material impact on International Propane net income.

2012 three-month period compared to the 2011 three-month period

Net income (loss) attributable to UGI Corporation by Business Unit:

	Three Months Ended December 31,		Variance - Favorable (Unfavorable)	
(Millions of dollars)	2012	2011	Amount	%
AmeriGas Propane	$ 18.2	$ 12.1	$ 6.1	50.4%
International Propane (a)	35.5	31.0	4.5	14.5%
Gas Utility	35.5	31.1	4.4	14.1%
Midstream & Marketing	15.8	13.9	1.9	13.7%
Corporate & Other	(2.4)	(1.1)	(1.3)	N.M.
Net income attributable to UGI Corporation	$ 102.6	$ 87.0	$ 15.6	17.9%

N.M. — Variance is not meaningful.
(a) 2011 net income includes adjustment to foreign tax credit valuation allowance which increased net income by $5.5 million.

AmeriGas Propane:

For the three months ended December 31,	2012		2011		Increase	
(Millions of dollars)						
Revenues	$	876.6	$	683.8	$ 192.8	28.2%
Total margin (a)	$	424.5	$	240.0	$ 184.5	76.9%
Partnership EBITDA (b)	$	187.8	$	83.7	$ 104.1	124.4%
Operating income (b)	$	139.9	$	60.1	$ 79.8	132.8%
Retail gallons sold (millions)		350.7		220.9	129.8	58.8%
Degree days—% (warmer) than normal (c)		(9.0)%		(11.9)%	—	—

(a) Total margin represents total revenues less total cost of sales.

(b) Partnership EBITDA (earnings before interest expense, income taxes and depreciation and amortization) 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 accounting principles generally accepted in the United States of America. Management uses Partnership EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 6 to condensed consolidated financial statements). Partnership EBITDA for the three months ended December 31, 2012 and 2011, includes acquisition and transition expenses of $5.5 million and $3.7 million, respectively, associated with Heritage Propane.

(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.

Results for the 2012 three-month period reflect the operations of Heritage Propane acquired in January 2012. Based upon heating degree-day data, temperatures in the Partnership’s service territories during the 2012 three-month period averaged approximately 9.0% warmer than normal but 3.4% colder than the 2011 three-month period. AmeriGas Propane retail gallons sold were 129.8 million gallons greater than in the prior-year period principally reflecting the impact of the Heritage Propane operations.

Retail propane revenues increased $186.7 million during the 2012 three-month period reflecting the higher retail volumes sold ($342.5 million) partially offset by a decline in average retail selling prices ($155.8 million), the result of lower propane product costs. Wholesale propane revenues declined $27.0 million principally reflecting lower wholesale volumes sold ($13.4 million) and lower average wholesale propane selling prices ($13.6 million). Average daily wholesale propane commodity prices during the 2012 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 38% lower than such prices during the prior-year three-month period. Total revenues from fee income and other ancillary sales and services in the 2012 three-month period were $33.1 million higher than in the 2011 three-month period principally reflecting such revenues from Heritage Propane. Total cost of sales increased $8.3 million principally reflecting the effects of the greater retail volumes sold ($221.2 million) and greater cost of sales associated with ancillary sales and services ($8.7 million) partially offset by the effects of lower average propane product costs on retail propane cost of sales ($194.6 million) and lower wholesale cost of sales ($27.1 million).

Total margin increased $184.5 million in the 2012 three-month period principally reflecting higher total propane margin ($160.2 million) and greater total margin from ancillary sales and services ($24.3 million). These increases principally reflect the incremental effects of Heritage Propane and, with respect to total propane margin, higher 2012 three-month period average unit margins reflecting the lower propane product costs.

Partnership EBITDA in the 2012 three-month period increased $104.1 million principally reflecting the higher total margin ($184.5 million) partially offset by higher operating and administrative expenses ($83.6 million) primarily attributable to incremental expenses associated with Heritage Propane operations. Operating and administrative expenses in the 2012 three-month period include $5.5 million of transition expenses associated with Heritage Propane while operating and administrative expenses in the prior-year period include Heritage Propane acquisition-related expenses of $3.7 million. Operating income increased $79.8 million in the 2012 three-month period principally reflecting the higher Partnership EBITDA ($104.1 million) partially offset by greater depreciation and amortization expense ($25.2 million) principally associated with Heritage Propane.

International Propane:

For the three months ended December 31,	2012	2011	Increase	
(Millions of dollars)				
Revenues	$ 664.9	$ 518.3	$ 146.6	28.3%
Total margin (a)	$ 190.1	$ 174.5	$ 15.6	8.9%
Operating income	$ 57.8	$ 41.7	$ 16.1	38.6%
Income before income taxes	$ 50.0	$ 34.1	$ 15.9	46.6%
Retail gallons sold (b)	172.8	164.1	8.7	5.3%
Antargaz degree days—% (warmer) than normal (c)	(7.7)%	(19.7)%	—	—
Flaga degree days—% (warmer) than normal (c)	(3.2)%	(4.9)%	—	—

(a) Total margin represents total revenues less total cost of sales.
(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 service territory and the 30-year period 1971-2000 at locations in our Flaga service territory.

Based upon heating degree day data, temperatures in our French operations during the 2012 three-month period were approximately 7.7% warmer than normal but significantly colder than the weather experienced in the prior-year period. Temperatures in our Flaga operations were approximately 3.2% warmer than normal and slightly colder than the prior year. During the 2012 three-month period, the average wholesale commodity price for propane in northwest Europe was approximately 30% higher than in the prior-year period while the average wholesale commodity price for butane was approximately 20% higher than the prior-year period. Retail LPG gallons sold were higher than the prior-year period principally reflecting the effects of the significantly colder weather and greater crop drying volumes at Antargaz.

Our International Propane base-currency results are translated into U.S. dollars based upon exchange rates experienced during each of the reporting periods. The functional currency of a significant portion of our International Propane results is the euro. During the 2012 and 2011 three-month periods, the average un-weighted translation rate was approximately $1.30 and $1.35 per euro, respectively. The difference in rates did not have a material impact on net income attributable to UGI.

International Propane revenues increased $146.6 million principally reflecting the effects of greater average LPG prices and to a much lesser extent the greater volumes sold. Cost of sales increased to $474.8 million in the 2012 three-month period from $343.8 million in the prior-year period principally reflecting higher average LPG commodity costs and, to a much lesser extent, the effects of the greater volumes sold.

Total International Propane margin increased $15.6 million during the 2012 three-month period principally reflecting the greater retail volumes sold at Antargaz and the effects of slightly higher retail unit margins at Flaga.

International Propane operating income and income before income taxes were $16.1 million and $15.9 million, respectively, higher than the prior-year period principally reflecting the higher total margin ($15.6 million). Total International Propane operating and administrative expenses were comparable with the prior year. Operating and administrative costs in the 2012 three-month period include higher delivery costs associated with the increased volumes at Antargaz while the prior-year period includes acquisition and transition costs of approximately $3.6 million associated with the businesses acquired from Shell in October 2011.

Gas Utility:

For the three months ended December 31,	2012	2011	Increase (Decrease)	
(Millions of dollars)				
Revenues	$ 248.3	$ 255.0	$ (6.7)	(2.6)%
Total margin (a)	$ 124.7	$ 113.3	$ 11.4	10.1 %
Operating income	$ 69.8	$ 61.2	$ 8.6	14.1 %
Income before income taxes	$ 60.2	$ 51.1	$ 9.1	17.8 %
System throughput—billions of cubic feet ("bcf") —				
Core market	21.8	19.4	2.4	12.4 %
Total	54.0	49.0	5.0	10.2 %
Degree days—% (warmer) than normal (b)	(3.6)%	(12.2)%	—	—

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

Temperatures in the Gas Utility service territory in the 2012 three-month period based upon heating degree days were 3.6% warmer than normal but 9.6% colder than the prior-year period. Total distribution system throughput increased principally reflecting greater throughput to core market customers and greater volumes associated with lower margin firm and interruptible delivery service 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 system throughput to core-market customers was above last year principally reflecting the effects of the colder weather and, to a much lesser extent, customer growth over the last several years, principally conversions from oil, prompted by sustained lower natural gas prices and high oil prices.

Notwithstanding the increase in system throughput, Gas Utility revenues decreased $6.7 million during the 2012 three-month period principally reflecting lower revenues from off-system sales ($6.3 million) and a decline in revenues from retail core-market customers ($6.0 million). These decreases were partially offset by higher revenues from firm and interruptible delivery service customers from higher volumes. The decrease in retail core-market revenues principally reflects the effects on gas cost recovery revenues of lower average purchased gas cost ("PGC") rates resulting from lower natural gas prices ($22.2 million) partially offset by the effects on retail core-market revenues of greater retail core-market volumes. Under Gas Utility's PGC recovery mechanisms, 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 gas was $123.6 million in the 2012 three-month period compared with $141.7 million in the prior-year period principally reflecting lower average PGC rates ($22.2 million) and the lower off-system sales ($6.3 million) partially offset by the effects on cost of sales of the greater retail core-market volumes.

Gas Utility total margin increased $11.4 million in the 2012 three-month period principally reflecting higher core market margin ($8.6 million) and higher firm delivery service total margin. The higher core market total margin reflects the effects of the greater core market volumes.

The increase in Gas Utility operating income during the 2012 three-month period principally reflects the increase in total margin ($11.4 million) partially offset by higher operating and administrative expenses including, among other things, higher distribution system maintenance expenses and greater pension expense.

Midstream & Marketing:

For the three months ended December 31,	2012		2011		Increase		
(Millions of dollars)							
Revenues	$	241.9	$	238.8	$	3.1	1.3%
Total margin (a)	$	45.2	$	40.0	$	5.2	13.0%
Operating income	$	27.5	$	23.9	$	3.6	15.1%
Income before income taxes	$	26.5	$	22.8	$	3.7	16.2%

(a) Total margin represents total revenues less total cost of sales.

Midstream & Marketing total revenues increased $3.1 million in the 2012 three-month period principally reflecting, among other things, higher revenues from our Electric Generation business ($7.5 million), higher retail power revenues ($4.1 million) and higher revenues from gas gathering activities ($1.2 million) partially offset by lower revenues from natural gas marketing activities ($12.1 million) due to lower average natural gas prices.

Midstream & Marketing's total margin increased $5.2 million in the 2012 three-month period. The increase principally reflects higher margin from Electric Generation ($2.7 million) and greater combined margin from natural gas marketing, gas gathering, peaking and capacity management activities ($3.4 million). These increases were partially offset by lower total margin from storage activities reflecting, in large part, lower gains in the 2012 three-month period from derivative contracts used to economically hedge the value of certain storage inventories. Margin from Electric Generation was greater than the prior year principally reflecting the impact of higher electricity production from our Hunlock natural gas-fired generating station. In the prior-year period, the Hunlock electricity generating station was running at less than full capacity due to an accident at one unit and flood damage at another unit sustained late in Fiscal 2011.

Midstream & Marketing's operating income in the 2012 three-month period was $3.6 million higher than the prior-year period reflecting the previously mentioned increase in total margin ($5.1 million) and the absence of expenses recorded in the prior-year period associated with a planned outage at the Conemaugh electricity generating facility. These increases in operating income were partially offset by higher depreciation expense ($1.3 million), principally associated with peaking LNG liquefaction and storage facilities, and higher operating and administrative costs. The increase in income before income taxes reflects the greater operating income ($3.6 million).

Interest Expense and Income Taxes. Our consolidated interest expense was $24.3 million higher in the 2012 three-month period principally reflecting higher AmeriGas Propane interest expense ($24.7 million) principally on debt issued to fund the Heritage Acquisition. Income taxes as a percentage of pretax earnings was lower in the 2012 three-month period reflecting the effects of a higher percentage of income associated with noncontrolling interests, principally AmeriGas Partners, not subject to tax while taxes in the prior-year three-month period were reduced by $5.5 million as a result of the realization of previously unrecognized foreign tax credits.

FINANCIAL CONDITION AND LIQUIDITY

Financial Condition

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 proceeds from credit facilities or, in the case of Midstream & Marketing, also from a receivables purchase facility. Long-term cash needs are generally met through issuance of long-term debt or equity securities.

Our cash and cash equivalents totaled $348.1 million at December 31, 2012, compared with $319.9 million at September 30, 2012. Excluding cash and cash equivalents that reside at UGI's operating subsidiaries, at December 31, 2012 and September 30, 2012, UGI had $101.2 million and $107.9 million, respectively, of cash and cash equivalents.

The Company's debt outstanding at December 31, 2012, totaled $3,856.0 million (including current maturities of long-term debt of $164.4 million and bank loan borrowings of $333.2 million) compared to debt outstanding at September 30, 2012, of $3,679.4 million (including current maturities of long-term debt of $166.7 million and bank loan borrowings of $165.1 million). Total debt outstanding at December 31, 2012, consists of (1) $2,500.3 million of Partnership debt; (2) $601.5 million (€455.9 million) of International Propane debt; (3) $673.1 million of UGI Utilities' debt; (4) $69.0 million of Midstream & Marketing debt; and (5) $12.1 million of other debt.

AmeriGas Partners' total debt at December 31, 2012, includes $2,250.8 million of AmeriGas Partners' Senior Notes, $177.2 million of AmeriGas OLP bank loan borrowings and $72.3 million of other long-term debt.

International Propane's total debt at December 31, 2012, includes $501.5 million (€380 million) outstanding under Antargaz' Senior Facilities term loan and a combined $80.7 million (€61.2 million) outstanding under Flaga's three term loans. Total International Propane debt outstanding at December 31, 2012, also includes combined borrowings of $13.9 million (€10.5 million) outstanding under Flaga's working capital facilities and $5.4 million (€4.1 million) of other long-term debt.

UGI Utilities' total debt at December 31, 2012, includes $383 million of Senior Notes, $217 million of Medium-Term Notes and $73.1 million of bank loan borrowings.

AmeriGas Partners. AmeriGas OLP has a $525 million unsecured credit agreement ("AmeriGas Credit Agreement"). At December 31, 2012, there were $177.2 million of borrowings outstanding under the AmeriGas Credit Agreement which are classified as bank loans on the Condensed Consolidated Balance Sheet. Issued and outstanding letters of credit under the AmeriGas Credit Agreement, which reduce the amount available for borrowings, totaled $54.1 million at December 31, 2012. Average daily and peak bank loan borrowings outstanding under the AmeriGas Credit Agreement during the 2012 three-month period were $109.9 million and $200.5 million, respectively. The average daily and peak bank loan borrowings outstanding during the 2011 three-month period were $136.3 million and $226.0 million, respectively. At December 31, 2012, the Partnership's available borrowing capacity under the AmeriGas Credit Agreement was $293.7 million.

The Partnership's management believes that the Partnership will be able to meet its anticipated contractual commitments and projected cash needs during Fiscal 2013 from existing cash balances, cash expected to be generated from operations and borrowings available under the AmeriGas Credit Agreement.

International Propane. Antargaz has a Senior Facilities Agreement with a consortium of banks ("2011 Senior Facilities Agreement") consisting of a €380 million variable-rate term loan and a €40 million revolving credit facility. Scheduled maturities under the term loan are €38 million due May 2014, €34.2 million due May 2015, and €307.8 million due March 2016. Borrowings under the term loan bear interest at one-, two-, three- or nine-month euribor, plus a margin. Antargaz has entered into pay-fixed, receive-variable interest rate swaps to fix the underlying euribor rate of interest on the term loan at an average rate of approximately 2.45% through September 2015 and, thereafter, at a rate of approximately 3.71% through the date of the term loan's final maturity in March 2016. At December 31, 2012, the effective interest rate on Antargaz' term loan was 4.66%. Antargaz had no amounts outstanding under its revolving credit facility at December 31, 2012.

Antargaz' management believes that it will be able to meet its anticipated contractual commitments and projected cash needs during Fiscal 2013 with cash generated from operations and borrowings under its revolving credit facility.

Flaga has two principal working capital facilities (the "Flaga Credit Agreements") comprising (1) a €46 million multi-currency working capital facility which 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"). The Flaga Multi-Currency Working Capital Facility expires in September 2014 and the Euro Facility expires in September 2013. At December 31, 2012, there were €3.9 million ($5.2 million) of borrowings outstanding under the Flaga Credit Agreements.

Issued and outstanding guarantees, which reduce available borrowings under the Flaga Credit Agreements, totaled €19.9 million ($26.2 million) at December 31, 2012. The average daily and peak bank loan borrowings outstanding under the Flaga Credit Agreements during the 2012 three-month period were €11.6 million and €15.3 million, respectively. The average daily and peak bank loan borrowings outstanding under the Flaga Credit Agreements during the 2011 three-month period were €12.3 million and €13.4 million, respectively.

Flaga's management believes it will be able to meet its anticipated contractual commitments and projected cash needs during Fiscal 2013 with cash generated from operations and borrowings available under its working capital facilities.

UGI Utilities. UGI Utilities may borrow up to a total of $300 million under its credit agreement ("UGI Utilities Credit Agreement). The UGI Utilities Credit Agreement expires in October 2015. At December 31, 2012, there was $73.1 million outstanding under the UGI Utilities Credit Agreement. During the 2012 and 2011 three-month periods, average daily bank loan borrowings were $53.5 million and $29.7 million, respectively, and peak bank loan borrowings totaled $78.6 million and $70.5 million, respectively. Peak bank loan borrowings typically occur during the heating season months of December and January.

UGI Utilities' management believes that it will be able to meet its anticipated contractual and projected cash commitments during Fiscal 2013 with cash generated from Gas Utility and Electric Utility operations and borrowings available under the UGI Utilities Credit Agreement.

Midstream & Marketing. In December 2012, Energy Services amended and restated its unsecured credit agreement with a group of banks ("Energy Services Credit Agreement") to increase its borrowing capacity and extend its expiration (see Note 10 to condensed consolidated financial statements). The Energy Services Credit Agreement, which expires in June 2016, provides for borrowings of up to $240 million (including a $50 million sublimit for letters of credit). There were $36 million of borrowings outstanding under this facility at December 31, 2012. During the 2012 and 2011 three-month periods, peak borrowings under the Energy Services Credit Agreement were $85 million.

Energy Services also has a $200 million receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper. The Receivables Facility expires in April 2013, although the Receivables Facility may terminate prior to such date due to the termination of commitments of the Receivables Facility's back-up purchasers. Energy Services uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts and capital expenditures. Energy Services intends to extend its Receivables Facility prior to its scheduled expiration in April 2013.

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 commercial paper conduit of a major bank.

During the three months ended December 31, 2012 and 2011, Energy Services transferred trade receivables totaling $224.3 million and $251.2 million, respectively, to ESFC. During the three months ended December 31, 2012 and 2011, ESFC sold an aggregate $79.5 million and $94.0 million, respectively, of undivided interests in its trade receivables to the commercial paper conduit. At December 31, 2012, the balance of ESFC receivables was $69.3 million and there was $33 million sold to the commercial paper conduit. At December 31, 2011, the outstanding balance of ESFC receivables was $78.4 million and there were was $33.2 million sold to the commercial paper conduit. During the three months ended December 31, 2012 and 2011, peak amounts sold under the Receivables Facility were $46.5 million and $41.0 million, respectively, and average daily amounts sold were $6.9 million and $20.8 million, respectively.

Midstream & Marketing's management believes that Midstream & Marketing will be able to meet its anticipated contractual commitments and projected cash needs during Fiscal 2013 with cash expected to be generated from operations, borrowings available under the Energy Services Credit Agreement and Receivables Facility, and capital contributions from UGI.

Dividends and Distributions. During the three months ended December 31, 2012, UGI declared and paid a cash dividend equal to $0.27 per common share. On January 24, 2013, UGI's Board of Directors declared a quarterly dividend of $0.27 per common share. The dividend is payable April 1, 2013, to shareholders of record as of March 15, 2013.

During the three months ended December 31, 2012, the Partnership declared and paid quarterly distributions on all limited partner units at a rate of $0.80 per Common Unit for the quarter ended September 30, 2012. On January 23, 2013, the General Partner's Board of Directors approved a quarterly distribution of $0.80 per limited partner unit for the quarter ended December 31, 2012. The distribution will be paid on February 19, 2013, to unitholders of record on February 11, 2013.

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 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 (used) by operating activities was $31.1 million in the 2012 three-month period compared to $(22.4) million in the 2011 three-month period. Cash flow from operating activities before changes in operating working capital was $264.9 million in the 2012 three-month period compared to $153.4 million in the prior-year three-month period. The increase in cash flow from operating activities before changes in operating working capital reflects, among other things, the effects of the higher operating results in the 2012 three-month period, greater noncash charges for deferred income taxes and lower cash losses associated with settled commodity derivative contracts. Cash required to fund changes in operating working capital totaled $233.8 million in the 2012 three-month period compared to $175.8 million in the prior-year three-month period. The higher cash used to fund changes in operating working capital in the 2012 three-month period largely reflects, among other things, greater cash needed to fund changes in accounts receivable, customer deposits and accrued interest largely reflecting the impact of AmeriGas Propane's Heritage Propane acquisition.

Investing Activities. Cash flow used in investing activities was $93.4 million in the 2012 three-month period compared with $243.4 million in the prior-year period. Investing activity cash flow is principally affected by expenditures for property, plant and equipment; cash paid for acquisitions of businesses; changes in restricted cash balances and proceeds from sales of assets. Cash paid for acquisitions in the prior-year three-month period principally reflects the October 2011 acquisition of certain of Shell’s European LPG businesses.

Financing Activities. Cash flow provided by financing activities was $87.5 million in the 2012 three-month period compared with cash flow used by financing activities of $256.7 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 bank loan borrowings; dividends and distributions on UGI Common Stock and AmeriGas Partners Common Units and issuances of UGI and AmeriGas Partners equity instruments.

Distributions on AmeriGas Partners publicly held Common Units in the 2012 three-month period increased over the prior-year period reflecting the greater number of Common Units outstanding resulting from the Heritage Propane acquisition and higher quarterly per-unit distribution rates. Net bank loan borrowings totaled $134.7 million in the 2012 three-month period compared to net bank loan borrowings of $265 million in the prior-year period. The decrease primarily reflects $49 million of net repayments under the Energy Services Credit Agreement in the 2012 three-month period compared with $75 million of borrowings under this agreement in the prior-year period.

Utility Matters

On October 3, 2012, UGI Utilities and the PUC Bureau of Investigation and Enforcement (“PUC Staff”) submitted a Joint Settlement Petition (“Joint Settlement”) to settle all regulatory compliance issues raised in the PUC Staff's formal complaint, issued on June 11, 2012 (“PUC Staff Complaint”), pertaining to a natural gas explosion which occurred on February 9, 2011, in Allentown, Pennsylvania and resulted in five deaths, several personal injuries and significant property damage (the “Incident”). The PUC Commissioners adopted a Joint Motion on January 24, 2013 (the “Joint Motion”) to adopt the Joint Settlement, with certain modifications. In addition to the commitments made by UGI Utilities in the Joint Settlement, the Joint Motion would require UGI Utilities to (i) pay a civil penalty amount that increases the amount provided in the Joint Settlement from $0.4 million to $0.5 million; (ii) conduct a pilot new technology leak detection program in Allentown; and (iii) accept new reporting requirements governing its agreed upon 14-year cast iron and 30-year bare steel pipeline replacement program and distribution integrity management program, but would not require UGI Utilities to concede to having violated any regulation or operating procedure. We anticipate that the PUC Staff will issue in the near future a tentative order that incorporates the terms and conditions of the Joint Settlement, as modified. The provisions of the tentative order will become final and effective unless any party to the Joint Settlement objects to any of the terms and conditions included in the tentative order within five business days from the date of the issuance. The Company does not believe that the cost of complying with the requirements of the Joint Motion will have a material impact on UGI Utilities' consolidated financial position, results of operations or cash flows.

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 International Propane 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 International Propane 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. 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. Our International Propane operations have used 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.

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, 2012 and 2011, the fair values of Gas Utility’s natural gas futures and option contracts were losses of $0.4 million and $2.6 million, respectively.

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 financial transmission rights (“FTRs”) and forward electricity purchase contracts, associated with our Electric Utility operations. At December 31, 2012 and 2011, the fair values of Electric Utility’s electricity supply contracts were losses of $8.2 million and $13.5 million, respectively. At December 31, 2012 and 2011, 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 other income. The amount of unrealized gains on these contracts and associated volumes under contract at December 31, 2012, were not material.

Midstream & Marketing purchases FTRs to economically hedge certain transmission costs that may be associated with its fixed-price electricity sales contracts. In addition, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later sale of natural gas or propane. Although Midstream & Marketing’s FTRs and NYMEX futures contracts associated with the purchase and later anticipated sale of natural gas and propane are generally effective as economic hedges, they do not currently qualify for hedge accounting treatment.

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 and over-the-counter natural gas and electricity futures contracts or enters into fixed-price supply arrangements. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to 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 has entered into and may continue to enter into fixed-price propane sales agreements. In order to manage the market price risk relating to substantially all of its fixed-price propane sales agreements, Midstream & Marketing enters into price swap and option contracts.

UGID 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, UGID 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 the UGID's results.

The fair value of unsettled commodity price risk sensitive derivative instruments held at December 31, 2012 (excluding those Gas Utility and Electric Utility commodity derivative instruments which are refundable to or recoverable from customers) was a loss of $31.1 million. A hypothetical 10% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would increase such loss by approximately $32.4 million at December 31, 2012.

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, 2012, includes our bank loan 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. At December 31, 2012, combined borrowings outstanding under these variable-rate debt agreements, excluding Antargaz' and Flaga's effectively fixed-rate debt, totaled $333.2 million.

Long-term debt associated with our domestic businesses is typically issued at fixed rates of interest based upon market rates for debt having similar terms and credit ratings. As these long-term debt issues mature, we may refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce interest rate risk associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs").

The fair value of unsettled interest rate risk sensitive derivative instruments held at December 31, 2012 (including pay-fixed, receive-variable interest rate swaps) was a loss of $67.6 million. A hypothetical 10% adverse change in the three-month euribor would increase such loss by approximately $8.8 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"). At December 31, 2012, 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, 2012, by approximately $85 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 amount of dollar-denominated purchases of LPG associated with such contracts generally represents approximately 15% - 30% of estimated dollar-denominated purchases to occur during the heating-season months of October to March.

The fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at December 31, 2012, was a loss of $2.4 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 $12.0 million.

Because a significant portion of our derivative instruments qualify as hedges under GAAP, we expect that changes in the fair value of derivative instruments used to manage commodity, currency or interest rate market risk would be substantially offset by gains or losses on the associated anticipated transactions.

Derivative Financial Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative financial instrument counterparties. Our derivative financial 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.

Certain of our derivative instrument 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 and option contracts generally require cash deposits in margin accounts. Declines in natural gas, LPG and electricity product costs can require our business units to post collateral with counterparties or make margin deposits to brokerage accounts. At December 31, 2012 and 2011, restricted cash in brokerage accounts totaled $6.9 million and $22.3 million, respectively.

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 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.

PART II OTHER INFORMATION

1A. RISK FACTORS

In addition to the other 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, 2012, 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 registration number or 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	Change in Control Agreement for Kirk R. Oliver dated as of October 1, 2012			
10.2	Amended and Restated Credit Agreement, dated as of December 18, 2012, among UGI Energy Services, Inc., as borrower, and JPMorgan Chase Bank, N.A., as administrative agent, PNC Bank, National Association, as syndication agent, and Wells Fargo Bank, National Association, as documentation agent	UGI	Form 8-K (12/18/2012)	10.1
10.3	AmeriGas Propane, Inc. 2010 Long-Term Incentive Plan on Behalf of AmeriGas Partners, L.P. Phantom Unit Grant Letter for Employees dated December 3, 2012	AmeriGas Partners, L.P.	Form 10-Q (12/31/2012)	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, 2012, 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, 2012, 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, 2012, 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			

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 8, 2013	By: /s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: February 8, 2013	By: /s/ Davinder S. Athwal Davinder S. Athwal Vice President—Accounting and Financial Control and Chief Risk Officer

EXHIBIT INDEX

10.1	Change in Control Agreement for Kirk R. Oliver dated as of October 1, 2012
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Exhibit 10.1

CHANGE IN CONTROL AGREEMENT

This CHANGE IN CONTROL AGREEMENT ("Agreement") is made as of October 1, 2012, between UGI Corporation (the "Company") and **Kirk R. Oliver** (the "Employee").

WHEREAS, the Company has determined that appropriate steps should be taken to reinforce and encourage the continued attention and dedication of key members of the Company's management to their assigned duties without distraction arising from the possibility of a Change in Control (as defined below), although no such change is now contemplated;

WHEREAS, in order to induce the Employee to remain in the employ of the Company, the Company agrees that the Employee shall receive the compensation set forth in this Agreement in the event the Employee's employment with the Company is terminated in connection with a Change in Control as a cushion against the financial and career impact on the Employee of any such Change in Control;

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter set forth and intending to be legally bound hereby, the parties hereby agree as follows:

1. Definitions. For all purposes of this Agreement, the following terms shall have the meanings specified in this Section unless the context clearly otherwise requires:

(a) "Affiliate" and "Associate" shall have the respective meanings ascribed to such terms in Rule 12b-2 of Regulation 12B under the Exchange Act.

(b) A Person shall be deemed the "Beneficial Owner" of any securities: (i) that such Person or any of such Person's Affiliates or Associates, directly or indirectly, has the right to acquire (whether such right is exercisable immediately or only after the passage of time) pursuant to any agreement, arrangement or understanding (whether or not in writing) or upon the exercise of conversion rights, exchange rights, rights, warrants or options, or otherwise; provided, however, that a Person shall not be deemed the "Beneficial Owner" of securities tendered pursuant to a tender or exchange offer made by such Person or any of such Person's Affiliates or Associates until such tendered securities are accepted for payment, purchase or exchange; (ii) that such Person or any of such Person's Affiliates or Associates, directly or indirectly, has the right to vote or dispose of or has "beneficial ownership" of (as determined pursuant to Rule 13d-3 of Regulation 13D-G under the Exchange Act), including without limitation pursuant to any agreement, arrangement or understanding, whether or not in writing; provided, however, that a Person shall not be deemed the "Beneficial Owner" of any security under this clause (ii) as a result of an oral or written agreement, arrangement or understanding to vote such security if such agreement, arrangement or understanding (A) arises solely from a revocable proxy given in response to a public proxy or consent solicitation made pursuant to, and in accordance with, the applicable provisions of the Proxy Rules under the Exchange Act, and (B) is not then reportable by such Person on Schedule 13D under the Exchange Act (or any comparable or successor report); or (iii) that are beneficially owned, directly or indirectly, by any other Person (or any Affiliate or Associate thereof) with which such Person (or any of such Person's Affiliates or Associates) has any agreement, arrangement or understanding (whether or not in writing) for the purpose of acquiring, holding, voting (except pursuant to a revocable proxy as described in the proviso to clause (ii) above) or disposing of any voting securities of the Company; provided, however, that nothing in this Section 1(b) shall cause a Person engaged in business as an underwriter of securities to be the "Beneficial Owner" of any securities acquired through such Person's participation in good faith in a firm commitment underwriting until the expiration of 40 days after the date of such acquisition.

(c) "Board" shall mean the Board of Directors of the Company.

(d) "Cause" shall mean (i) misappropriation of funds, (ii) habitual insobriety or substance abuse, (iii) conviction of a crime involving moral turpitude, or (iv) gross negligence in the performance of duties, which gross negligence has had a material adverse effect on the business, operations, assets, properties or financial condition of the Company. The determination of Cause shall be made by an affirmative vote of at least two-thirds of the members of the Board at a duly called meeting of the Board.

(e) "Change in Control" shall have the meaning set forth in the attached Exhibit A to this Agreement.

(f) "COBRA Cost" shall mean 100% of the "applicable premium" under section 4980B(f)(4) of the Code for continued medical and dental COBRA Coverage under the Company's benefit plans.

(g) "COBRA Coverage" shall mean continued medical and dental coverage under the Company's benefit plans, as determined under section 4980B of the Code.

(h) "Code" shall mean the Internal Revenue Code of 1986, as amended.

(i) "Compensation Committee" shall mean the Compensation and Management Development Committee of the Board.

(j) "Continuation Period" shall mean the **Three-**year period beginning on the Employee's Termination Date.

(k) "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

(l) "Executive Severance Plan" shall mean the Company's Senior Executive Employee Severance Pay Plan, as in effect from time to time.

(m) "Good Reason Termination" shall mean a Termination of Employment initiated by the Employee upon one or more of the following occurrences:

(i) a material breach by the Company of any terms of this Agreement, including without limitation a material breach of Section 2 or 13 of this Agreement;

(ii) a material diminution in the authority, duties or responsibilities held by the Employee immediately prior to the Change in Control;

(iii) a material diminution in the Employee's base compensation as in effect immediately prior to the Change in Control; or

(iv) a material change in the geographic location at which the Employee must perform services (which, for purposes of this Agreement, means the Employee is required to report, other than on a temporary basis (less than 12 months), to a location which is more than 50 miles from the Employee's principal place of business immediately preceding the Change in Control, without the Employee's express written consent).

Notwithstanding the foregoing, the Employee shall be considered to have a Good Reason Termination only if the Employee provides written notice to the Company, pursuant to Section 3, specifying in reasonable detail the events or conditions upon which the Employee is basing such Good Reason Termination and the Employee provides such notice within 90 days after the event that gives rise to the Good Reason Termination. Within 30 days after notice has been provided, the Company shall have the opportunity, but shall have no obligation, to cure such events or conditions that give rise to the Good Reason Termination. If the Company does not cure such events or conditions within the 30-day period, the Employee may terminate employment with the Company based on Good Reason Termination within 30 days after the expiration of the cure period.

(n) "Key Employee" shall mean an employee who, at any time during the 12-month period ending on the identification date, is a "specified employee" under section 409A of the Code, as determined by the Compensation Committee or its delegate. The determination of Key Employees, including the number and identity of persons considered specified employees and the identification date, shall be made by the Compensation Committee or its delegate in accordance with the provisions of section 409A of the Code and the regulations issued thereunder.

(o) "Postponement Period" shall mean, for a Key Employee, the period of six months after separation from service (or such other period as may be required by section 409A of the Code), during which severance payments may not be paid to the Key Employee under section 409A of the Code.

(p) "Release" shall mean a release of any and all claims against the Company, its Affiliates, its Subsidiaries and all related parties with respect to all matters arising out of the Employee's employment by the Company and its Affiliates and Subsidiaries, or the termination thereof (other than claims relating to amounts payable under this Agreement or benefits accrued under any plan, program or arrangement of the Company or any of its Subsidiaries or Affiliates) and shall be in the form required by the Company of its terminating executives immediately prior to the Change in Control.

(q) "Subsidiary" shall mean any corporation in which the Company, directly or indirectly, owns at least a 50% interest or an unincorporated entity of which the Company, directly or indirectly, owns at least 50% of the profits or capital interests.

(r) "Termination Date" shall mean the effective date of the Employee's Termination of Employment, as specified in the Notice of Termination.

(s) "Termination of Employment" shall mean the termination of the Employee's actual employment relationship with the Company and its Subsidiaries and Affiliates.

2. Employment. After a Change in Control, during the term of the Agreement, Employee shall continue to serve in the same or a comparable executive position with the Company as in effect immediately before the Change in Control, and with the same or a greater target level of annual and long-term compensation as in effect immediately before the Change in Control.

3. Notice of Termination. Any Termination of Employment upon or following a Change in Control shall be communicated by a Notice of Termination to the other party hereto given in accordance with Section 14 hereof. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific provision in this Agreement relied upon, (ii) briefly summarizes the facts and circumstances deemed to provide a basis for the Employee's Termination of Employment under the provision so indicated, and (iii) if the Termination Date is other than the date of receipt of such notice, specifies the Termination Date (which date shall not be more than 15 days after the giving of such notice) except as provided in Section 1(m) above.

4. Severance Compensation upon Termination of Employment.

(a) In the event of the Employee's involuntary Termination of Employment by the Company or a Subsidiary or Affiliate for any reason other than Cause or in the event of a Good Reason Termination, in either event upon or within two years after a Change in Control, the Employee will receive the following amounts in lieu of any severance compensation and benefits under the Executive Severance Plan or any other severance plan of the Company or a Subsidiary or Affiliate:

(i) The Company shall pay to the Employee a lump sum cash payment equal to the greater of (A) or (B) as set forth below:

(A) The Separation Pay and Paid Notice as calculated under the terms of the Executive Severance Plan based on the Employee's compensation and service as of the Termination Date, or

(B) **Three** multiplied by the sum of (1) the Employee's annual base salary plus (2) the Employee's annual bonus. The annual base salary for this purpose shall be the Employee's annual base salary in effect as of the Employee's Termination Date. The annual bonus shall be calculated for this purpose as the greater of (x) the average annual cash bonus paid to the Employee for the three full fiscal years of the Company preceding the fiscal year in which the Termination Date occurs or (y) the Employee's target annual cash bonus for the fiscal year in which the Termination Date occurs. For purposes of the preceding sentence, if the Employee has not received an annual cash bonus for three full fiscal years, the Employee's average annual cash bonus shall be determined by dividing the total annual cash bonuses received by the Employee during the preceding three full fiscal years by the number of full and fractional years for which the Employee received an annual cash bonus during such three-year period.

(ii) The Company shall pay to the Employee a single lump sum payment equal to the COBRA Cost that the Employee would incur if the Employee continued medical and dental coverage under the Company's benefit plans during the Continuation Period, based on the benefits in effect for the Employee (and, if applicable, his or her spouse and dependents) at the Termination Date, less the amount that the Employee would be required to contribute for medical and dental coverage if the Employee were an active employee. The cash payment shall include a tax gross up payment equal to 75% of the lump sum amount described in the preceding sentence. The Employee may elect continuation coverage under the Company's applicable medical and dental plans during the Continuation Period by paying the COBRA Cost of such coverage. COBRA Coverage shall run concurrently with the Continuation Period, and nothing in this Section shall limit the Employee's right to elect COBRA Coverage for the full period permitted by law.

(iii) The Employee's benefit under the Company's executive retirement plan in which the Employee participates shall be calculated as if the Employee had continued in employment during the Continuation Period, earning base salary and bonus at the annual rate calculated under subsection (i)(B) above.

(iv) The Company shall pay to the Employee an amount equal to the Employee's target annual cash bonus amount for the Company's fiscal year in which the Termination Date occurs, multiplied by the number of months (with a partial month counting as a full month) elapsed in the fiscal year to the Termination Date and divided by 12, as well as any amounts due but not yet paid from the prior year under such plan.

(b) Notwithstanding the foregoing, no payments shall be made to the Employee under this Section 4 unless the Employee signs and does not revoke a Release. The amounts described in subsections (a) (i), (ii) and (iv) above shall be paid on the 30th day after the Termination Date subject to the Company's receipt of a Release and expiration of the revocation period for the Release. Payments under this Agreement shall be made by mail to the last address provided for notices to the Employee pursuant to Section 14 of this Agreement.

5. Other Payments.

Upon any Termination of Employment entitling the Employee to payments under this Agreement, the Employee shall receive all accrued but unpaid salary and all benefits accrued and payable under any plans, policies and programs of the Company and its Subsidiaries or

Affiliates, provided that the Employee shall not receive severance benefits under the Executive Severance Plan or any other severance plan of the Company or a Subsidiary or Affiliate.

6. Interest; Enforcement.

(a) If the Company shall fail or refuse to pay any amounts due the Employee under Section 4 on the applicable due date, the Company shall pay interest at the rate described below on the unpaid payments from the applicable due date to the date on which such amounts are paid. Interest shall be credited at an annual rate equal to the rate listed in the *Wall Street Journal* as the "prime rate" as of the Employee's Termination Date, plus 1%, compounded annually.

(b) It is the intent of the parties that the Employee not be required to incur any expenses associated with the enforcement of the Employee's rights under this Agreement by arbitration, litigation or other legal action, because the cost and expense thereof would substantially detract from the benefits intended to be extended to the Employee hereunder. Accordingly, the Company shall pay the Employee on demand the amount necessary to reimburse the Employee in full for all reasonable expenses (including all attorneys' fees and legal expenses) incurred by the Employee in enforcing any of the obligations of the Company under this Agreement. The Employee shall notify the Company of the expenses for which the Employee demands reimbursement within 60 days after the Employee receives an invoice for such expenses, and the Company shall pay the reimbursement amount within 15 days after receipt of such notice.

7. No Mitigation. The Employee shall not be required to mitigate the amount of any payment or benefit provided for in this Agreement by seeking other employment or otherwise, nor shall the amount of any payment or benefit provided for herein be reduced by any compensation earned by other employment or otherwise.

8. Non-Exclusivity of Rights. Nothing in this Agreement shall prevent or limit the Employee's continuing or future participation in or rights under any benefit, bonus, incentive or other plan or program provided by the Company, or any of its Subsidiaries or Affiliates, and for which the Employee may qualify.

9. No Set-Off. The Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which the Company may have against the Employee or others.

10. Taxation. All payments under this Agreement shall be subject to all requirements of the law with regard to tax withholding and reporting and filing requirements, and the Company shall use its best efforts to satisfy promptly all such requirements.

11. Effect of Section 280G on Payments.

(a) Notwithstanding any other provisions of this Agreement to the contrary, in the event that it shall be determined that any payment or distribution in the nature of compensation (within the meaning of section 280G(b)(2) of the Code) to or for the benefit of the Employee, whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (the "Payments"), would constitute an "excess parachute payment" within the meaning of section 280G of the Code, the Company shall reduce (but not below zero) the aggregate present value of the Payments under the Agreement to the Reduced Amount (as defined below), if reducing the Payments under this Agreement will provide the Employee with a greater net after-tax amount than would be the case if no reduction was made. The Payments shall be reduced as described in the preceding sentence only if (A) the net amount of the Payments, as so reduced (and after subtracting the net amount of federal, state and local income and payroll taxes on the reduced Payments), is greater than or equal to (B) the net amount of the Payments without such reduction (but after subtracting the net amount of federal, state and local income and payroll taxes on the Payments and the amount of Excise Tax (as defined below) to which the Employee would be subject with respect to the unreduced Payments). Only amounts payable under this Agreement shall be reduced pursuant to this subsection (a). The "Reduced Amount" shall be an amount expressed in present value that maximizes the aggregate present value of Payments under this Agreement without causing any Payment under this Agreement to be subject to the Excise Tax, determined in accordance with section 280G(d)(4) of the Code. The term "Excise Tax" means the excise tax imposed under section 4999 of the Code, together with any interest or penalties imposed with respect to such excise tax.

(b) All determinations to be made under this Section 11 shall be made by an independent registered public accounting firm or consulting firm selected by the Company immediately prior to the Change in Control, which shall provide its determinations and any supporting calculations both to the Company and the Employee within 10 days of the Change in Control. Any such determination by such firm shall be binding upon the Company and the Employee.

(c) All of the fees and expenses of the firm in performing the determinations referred to in this Section shall be borne solely by the Company.

12. Term of Agreement. The term of this Agreement shall be for three years from the date hereof and shall be automatically renewed for successive one-year periods unless the Company notifies the Employee in writing that this Agreement will not be renewed at least 60 days prior to the end of the then current term; provided, however, that (i) if a Change in Control occurs during the term of this Agreement, this Agreement shall remain in effect for two years following such Change in Control or until all of the obligations of the parties hereunder are satisfied or have expired, if later, and (ii) this Agreement shall terminate if the Employee's employment with the Company terminates for any reason before a Change in Control (regardless of whether the Employee is thereafter employed by a Subsidiary or Affiliate of the Company).

13. Successor Company. The Company shall require any successor or successors (whether direct or indirect, by purchase, merger or otherwise) to all or substantially all of the business or assets of the Company, by agreement in form and substance satisfactory to the Employee, to acknowledge expressly that this Agreement is binding upon and enforceable against the Company in accordance with the terms hereof, and to become jointly and severally

obligated with the Company to perform this Agreement in the same manner and to the same extent that the Company would be required to perform if no such succession or successions had taken place. Failure of the Company to notify the Employee in writing as to such successorship, to provide the Employee the opportunity to review and agree to the successor's assumption of this Agreement or to obtain such agreement prior to the effectiveness of any such succession shall be a breach of this Agreement. As used in this Agreement, the Company shall mean the Company as defined above and any such successor or successors to its business or assets, jointly and severally.

14. Notice. All notices and other communications required or permitted hereunder or necessary or convenient in connection herewith shall be in writing and shall be delivered personally or mailed by registered or certified mail, return receipt requested, or by overnight express courier service, as follows:

If to the Company, to:

460 North Gulph Road
King of Prussia, PA 19406
Attention: Corporate Secretary

If to the Employee, to the most recent address provided by the Employee to the Company or a Subsidiary or Affiliate for payroll purposes,

or to such other address as the Company or the Employee, as the case may be, shall designate by notice to the other party hereto in the manner specified in this Section; provided, however, that if no such notice is given by the Company following a Change in Control, notice at the last address of the Company or any successor pursuant to Section 13 shall be deemed sufficient for the purposes hereof. Any such notice shall be deemed delivered and effective when received in the case of personal delivery, five days after deposit, postage prepaid, with the U.S. Postal Service in the case of registered or certified mail, or on the next business day in the case of overnight express courier service.

15. Section 409A of the Code.

(a) This Agreement is intended to meet the requirements of the "short-term deferral exception," "separation pay exception" and other exceptions under section 409A of the Code, as applicable. However, if the Employee is a Key Employee and if required by section 409A of the Code, no payments or benefits under this Agreement shall be paid to the Employee during the Postponement Period. If payment is required to be delayed for the Postponement Period pursuant to section 409A, the accumulated amounts withheld on account of section 409A, with interest as described in Section 6 above, shall be paid in a lump sum payment within 15 days after the end of the Postponement Period. If the Employee dies during the Postponement Period prior to the payment of benefits, the amounts withheld on account of section 409A, with interest as described above, shall be paid to the Employee's estate within 60 days after the Employee's death.

(b) Notwithstanding anything in this Agreement to the contrary, if required by section 409A, payments may only be made under this Agreement upon an event and in a manner permitted by section 409A, to the extent applicable. As used in the Agreement, the term "termination of employment" shall mean the Employee's separation from service with the Company and its Subsidiaries and Affiliates within the meaning of section 409A and the regulations promulgated thereunder. For purposes of section 409A, each payment under the Agreement shall be treated as a separate payment. In no event may the Employee designate the year of payment for any amounts payable under the Agreement. All reimbursements and in-kind benefits provided under the Agreement shall be made or provided in accordance with the requirements of section 409A of the Code.

16. Governing Law. This Agreement shall be governed by and interpreted under the laws of the Commonwealth of Pennsylvania without giving effect to any conflict of laws provisions.

17. Contents of Agreement; Amendment. This Agreement supersedes all prior agreements with respect to the subject matter hereof (including without limitation any other change in control agreement in effect between the Company or a Subsidiary or Affiliate and the Employee) and sets forth the entire understanding between the parties hereto with respect to the subject matter hereof. This Agreement cannot be amended except pursuant to approval by the Board and a written amendment executed by the Employee and the Chair of the Compensation Committee. The provisions of this Agreement may require a variance from the terms and conditions of certain compensation or bonus plans under circumstances where such plans would not provide for payment thereof in order to obtain the maximum benefits for the Employee. It is the specific intention of the parties that the provisions of this Agreement shall supersede any provisions to the contrary in such plans, and such plans shall be deemed to have been amended to correspond with this Agreement without further action by the Company or the Board.

18. No Right to Continued Employment. Nothing in this Agreement shall be construed as giving the Employee any right to be retained in the employ of the Company or a Subsidiary or Affiliate.

19. Successors and Assigns. All of the terms and provisions of this Agreement shall be binding upon and inure to the benefit of and be enforceable by the respective heirs, representatives, successors and assigns of the parties hereto, except that the duties and responsibilities of the Employee and the Company hereunder shall not be assignable in whole or in part.

20. Severability. If any provision of this Agreement or application thereof to anyone or under any circumstances shall be determined to be invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions or applications of this Agreement which can be given effect without the invalid or unenforceable provision or application.

21. Remedies Cumulative; No Waiver. No right conferred upon the Employee by this Agreement is intended to be exclusive of any other right or remedy, and each and every such right or remedy shall be cumulative and shall be in addition to any other right or remedy given

hereunder or now or hereafter existing at law or in equity. No delay or omission by the Employee in exercising any right, remedy or power hereunder or existing at law or in equity shall be construed as a waiver thereof.

22. Miscellaneous. All section headings are for convenience only. This Agreement may be executed in several counterparts, each of which is an original. It shall not be necessary in making proof of this Agreement or any counterpart hereof to produce or account for any of the other counterparts.

23. Arbitration. In the event of any dispute under the provisions of this Agreement other than a dispute in which the sole relief sought is an equitable remedy such as an injunction, the parties shall be required to have the dispute, controversy or claim settled by arbitration in Montgomery County, Pennsylvania, in accordance with the commercial arbitration rules then in effect of the American Arbitration Association, before one arbitrator who shall be an executive officer or former executive officer of a publicly traded corporation, selected by the parties. Any award entered by the arbitrator shall be final, binding and nonappealable and judgment may be entered thereon by either party in accordance with applicable law in any court of competent jurisdiction. This arbitration provision shall be specifically enforceable. The arbitrator shall have no authority to modify any provision of this Agreement or to award a remedy for a dispute involving this Agreement other than a benefit specifically provided under or by virtue of the Agreement. The Company shall be responsible for all of the fees of the American Arbitration Association and the arbitrator and any expenses relating to the conduct of the arbitration (including reasonable attorneys' fees and expenses).

IN WITNESS WHEREOF, the undersigned, intending to be legally bound, have executed this Agreement as of the date first written above. By executing this Agreement, the undersigned acknowledge that this Agreement replaces and supersedes any other understanding regarding the matters described herein.

UGI Corporation

/s/ John L. Walsh
John L. Walsh
President and Chief Operating Officer

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

EXHIBIT A
UGI CORPORATION
CHANGE IN CONTROL

For purposes of this Agreement, "Change in Control" shall mean:

(i) Any Person (except the Employee, his Affiliates and Associates, the Company, any Subsidiary of the Company, any employee benefit plan of the Company or of any Subsidiary of the Company, or any Person or entity organized, appointed or established by the Company for or pursuant to the terms of any such employee benefit plan), together with all Affiliates and Associates of such Person, becomes the Beneficial Owner in the aggregate of 20% or more of either (A) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (B) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Company Voting Securities"); or

(ii) Individuals who, as of the beginning of any 24-month period, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board, provided that any individual becoming a director subsequent to the beginning of such period whose election or nomination for election by the Company's stockholders was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office is in connection with an actual or threatened election contest relating to the election of the Directors of the Company; or

(iii) Consummation by the Company of a reorganization, merger or consolidation (a "Business Combination"), in each case, with respect to which all or substantially all of the individuals and entities who were the respective Beneficial Owners of the Outstanding Company Common Stock and Company Voting Securities immediately prior to such Business Combination do not, following such Business Combination, Beneficially Own, directly or indirectly, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination in substantially the same proportion as their ownership immediately prior to such Business Combination of the Outstanding Company Common Stock and Company Voting Securities, as the case may be; or

(iv) (A) Consummation of a complete liquidation or dissolution of the Company or (B) sale or other disposition of all or substantially all of the assets of the Company other than to a corporation with respect to which, following such sale or disposition, more than 50% of, respectively, the then outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors is then owned beneficially, directly or indirectly, by all or substantially all of the individuals and entities who were the Beneficial Owners, respectively, of the Outstanding Company Common Stock and Company Voting Securities immediately prior to such sale or disposition in substantially the same proportion as their ownership of the Outstanding Company Common Stock and Company Voting Securities, as the case may be, immediately prior to such sale or disposition.

EXHIBIT 31.1

CERTIFICATION

I, Lon R. Greenberg, 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 8, 2013

/s/ Lon R. Greenberg

Lon R. Greenberg
Chairman 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 8, 2013

/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, Lon R. Greenberg, 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, 2012 (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/ Lon R. Greenberg	/s/ Kirk R. Oliver
Lon R. Greenberg	Kirk R. Oliver
Date: February 8, 2013	Date: February 8, 2013