UGI CORP /PA/
Form 10-Q
August 02, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2013
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________ to ________
Commission file number 1-11071

UGI CORPORATION
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
At July 31, 2013, there were 114,098,006 shares of UGI Corporation Common Stock, without par value, outstanding.

Table of Contents

UGI CORPORATION AND SUBSIDIARIES
TABLE OF CONTENTS

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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

	June 30, 2013	September 30, 2012	June 30, 2012
ASSETS			
Current assets:			
Cash and cash equivalents	$401.8	$319.9	$436.5
Restricted cash	6.0	3.0	7.6
Accounts receivable (less allowances for doubtful accounts of $48.0, $36.1 and $45.7, respectively)	752.6	632.6	624.9
Accrued utility revenues	11.8	16.9	15.0
Inventories	304.0	356.9	317.3
Deferred income taxes	27.3	56.8	52.3
Utility regulatory assets	3.7	6.5	2.7
Derivative financial instruments	18.7	13.2	21.6
Prepaid expenses and other current assets	36.1	98.7	59.4
Total current assets	1,562.0	1,504.5	1,537.3
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,495.4, $2,286.0 and $2,226.8, respectively)	4,325.0	4,233.1	4,188.9
Goodwill	2,834.0	2,818.3	2,756.0
Intangible assets, net	608.6	658.2	717.7
Other assets	499.2	495.6	452.3
Total assets	$9,828.8	$9,709.7	$9,652.2
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$195.6	$166.7	$86.1
Bank loans	135.9	165.1	187.3
Accounts payable	384.5	411.3	346.0
Derivative financial instruments	56.8	100.9	116.5
Other current liabilities	552.9	643.0	577.4
Total current liabilities	1,325.7	1,487.0	1,313.3
Long-term debt	3,298.2	3,347.6	3,475.1
Deferred income taxes	956.9	935.0	832.8
Deferred investment tax credits	4.4	4.6	4.7
Other noncurrent liabilities	613.5	616.7	589.5
Total liabilities	6,198.7	6,390.9	6,215.4
Commitments and contingencies (note 11)			
Equity:			
UGI Corporation stockholders' equity:			
UGI Common Stock, without par value (authorized—300,000,000 shares; issued — 115,759,694, 115,624,594 and 115,623,094 shares, respectively)	1,192.9	1,157.7	1,148.8
Retained earnings	1,361.9	1,166.1	1,211.2
Accumulated other comprehensive loss	(30.7)	(62.0)	(77.7)
Treasury stock, at cost	(26.2)	(28.7)	(24.3)
Total UGI Corporation stockholders' equity	2,497.9	2,233.1	2,258.0

Noncontrolling interests, principally in AmeriGas Partners	1,132.2	1,085.7	1,178.8
Total equity	3,630.1	3,318.8	3,436.8
Total liabilities and equity	$9,828.8	$9,709.7	$9,652.2

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2013	2012	2013	2012
Revenues	$1,372.3	$1,277.2	$5,932.6	$5,393.5
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	827.9	810.2	3,547.3	3,438.6
Operating and administrative expenses	404.7	405.8	1,297.4	1,191.5
Utility taxes other than income taxes	3.7	3.9	12.7	12.9
Depreciation	76.5	69.5	220.0	191.0
Amortization	15.4	15.1	46.3	36.7
Other income, net	(9.0)	(8.1)	(26.5)	(27.1)
	1,319.2	1,296.4	5,097.2	4,843.6
Operating income (loss)	53.1	(19.2)	835.4	549.9
(Loss) income from equity investees	—	(0.1)	0.1	(0.2)
Gain (loss) on extinguishments of debt	—	0.1	—	(13.3)
Interest expense	(59.2)	(61.3)	(179.6)	(162.6)
(Loss) income before income taxes	(6.1)	(80.5)	655.9	373.8
Income tax (expense) benefit	(9.0)	4.0	(174.1)	(113.2)
Net (loss) income	(15.1)	(76.5)	481.8	260.6
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	29.8	70.2	(192.6)	(46.5)
Net income (loss) attributable to UGI Corporation	$14.7	$(6.3)	$289.2	$214.1
Earnings (loss) per common share attributable to UGI Corporation stockholders:				
Basic	$0.13	$(0.06)	$2.54	$1.90
Diluted	$0.13	$(0.06)	$2.51	$1.89
Average common shares outstanding (thousands):				
Basic	114,240	112,726	113,693	112,484
Diluted	116,196	112,726	115,275	113,295
Dividends declared per common share	$0.2825	$0.27	$0.8225	$0.79

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Nine Months Ended June 30, 2013	Nine Months Ended June 30, 2012
Net (loss) income	$(15.1)	$(76.5)	$481.8	$260.6
Other comprehensive income (loss):				
Net losses on derivative instruments (net of tax of $(1.9), $9.3, $(4.5) and $48.6, respectively)	(11.0)	(63.2)	(11.1)	(143.9)
Reclassifications of net losses on derivative instruments (net of tax of $(1.6), $(9.5), $(15.1) and $(31.3), respectively)	8.9	24.8	59.7	69.5
Foreign currency adjustments (net of tax of $(2.4), $11.2, $1.8 and $9.7, respectively)	8.8	(35.6)	1.3	(33.9)
Benefit plans (net of tax of $(0.2), $(0.0), $(0.7) and $(0.2), respectively)	0.3	0.1	1.1	0.3
Other comprehensive income (loss)	7.0	(73.9)	51.0	(108.0)
Comprehensive (loss) income	(8.1)	(150.4)	532.8	152.6
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	37.8	107.3	(212.2)	(0.4)
Comprehensive income (loss) attributable to UGI Corporation	$29.7	$(43.1)	$320.6	$152.2

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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

	Nine Months Ended June 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$481.8	$260.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	266.3	227.7
Deferred income taxes, net	35.5	9.9
Provision for uncollectible accounts	23.9	21.3
Net change in realized gains and losses deferred as cash flow hedges	5.0	(11.7)
Loss on extinguishments of debt, net	—	13.3
Other, net	(11.3)	2.6
Net change in:		
Accounts receivable and accrued utility revenues	(141.1)	71.2
Inventories	54.1	128.1
Utility deferred fuel costs, net of changes in unsettled derivatives	20.5	8.1
Accounts payable	(26.9)	(132.2)
Other current assets	52.4	22.8
Other current liabilities	(73.8)	(55.5)
Net cash provided by operating activities	686.4	566.2
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(291.6)	(236.0)
Acquisitions of businesses, net of cash acquired	(24.3)	(1,573.7)
(Increase) decrease in restricted cash	(3.0)	9.6
Other, net	2.2	0.1
Net cash used by investing activities	(316.7)	(1,800.0)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(93.4)	(88.7)
Distributions on AmeriGas Partners Common Units	(168.5)	(126.5)
Issuances of debt	—	1,550.4
Repayments of debt	(28.5)	(240.1)
(Decrease) increase in bank loans	(39.0)	54.2
Receivables Facility net borrowings (repayments)	9.5	(4.3)
Issuances of UGI Common Stock	28.5	12.7
Issuance of AmeriGas Partners Common Units	—	276.6
Other	5.4	0.5
Net cash (used) provided by financing activities	(286.0)	1,434.8
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(1.8)	(3.0)
Cash and cash equivalents increase	$81.9	$198.0
Cash and cash equivalents:		
End of period	$401.8	$436.5
Beginning of period	319.9	238.5
Increase	$81.9	$198.0

See accompanying notes to condensed consolidated financial statements.

- 4 -

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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

	Nine Months Ended June 30,	
	2013	2012
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	19.7	7.6
Dividend reinvestment plan	1.4	1.6
Excess tax benefits realized on equity-based compensation	5.7	0.8
Stock-based compensation expense	8.4	7.0
Adjustments to reflect change in ownership of AmeriGas Partners, net of tax	—	194.4
Balance, end of period	$1,192.9	$1,148.8
Retained earnings		
Balance, beginning of period	$1,166.1	$1,085.8
Net income attributable to UGI Corporation	289.2	214.1
Cash dividends on Common Stock	(93.4)	(88.7)
Balance, end of period	$1,361.9	$1,211.2
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$(62.0)	$(17.7)
Net gains (losses) on derivative instruments, net of tax	6.6	(74.1)
Reclassification of net losses on derivative instruments, net of tax	22.3	45.8
Benefit plans, net of tax	1.1	0.3
Adjustments to reflect change in ownership of AmeriGas Partners, net of tax	—	1.9
Foreign currency, net of tax	1.3	(33.9)
Balance, end of period	$(30.7)	$(77.7)
Treasury stock		
Balance, beginning of period	$(28.7)	$(27.8)
Common Stock issued in connection with employee and director plans, net of tax withheld	20.8	2.9
Dividend reinvestment plan	0.8	0.6
Reacquired common stock - employee and director plans	(19.1)	—
Balance, end of period	$(26.2)	$(24.3)
Total UGI Corporation stockholders' equity	$2,497.9	$2,258.0
Noncontrolling interests		
Balance, beginning of period	$1,085.7	$213.4
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	192.6	46.5
Net losses on derivative instruments	(17.8)	(69.8)
Reclassification of net losses on derivative instruments	37.4	23.7
Dividends and distributions	(168.7)	(126.8)
AmeriGas Partners Common Unit public offering	—	276.6
AmeriGas Partners Common Units issued for Heritage Acquisition	—	1,132.6

Adjustments to reflect change in ownership of AmeriGas Partners	—	(321.4)
Other	3.0	4.0
Balance, end of period	$ 1,132.2	$ 1,178.8
Total equity	$ 3,630.1	$ 3,436.8

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES
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 retail propane marketing and distribution business through AmeriGas Partners, L.P. ("AmeriGas Partners"). AmeriGas Partners is a publicly traded limited partnership that conducts a national propane distribution business through its principal operating subsidiary AmeriGas Propane, L.P. ("AmeriGas OLP") and prior to its merger with AmeriGas OLP on July 1, 2013 (the "Merger"), AmeriGas OLP's principal operating subsidiary Heritage Operating, L.P. ("HOLP"). AmeriGas OLP and HOLP, prior to the Merger are collectively referred to herein as the "Operating Partnership." AmeriGas Partners and AmeriGas OLP are Delaware limited partnerships. UGI's wholly owned second-tier subsidiary, AmeriGas Propane, Inc. (the "General Partner"), serves as the general partner of AmeriGas Partners and AmeriGas OLP. We refer to AmeriGas Partners and its subsidiaries together as the "Partnership" and the General Partner and its subsidiaries, including the Partnership, as "AmeriGas Propane." At June 30, 2013, 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 39,492,279 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"). In July 2013, ETP sold 7,500,000 of the Common Units it held in an underwritten public offering. AmeriGas Partners did not receive any proceeds from the sale of the Common Units by ETP.

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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 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 June 30,		Nine Months Ended June 30,	
	2013	2012	2013	2012
Denominator (thousands of shares):				
Average common shares outstanding for basic computation	114,240	112,726	113,693	112,484
Incremental shares issuable for stock options and awards	1,956	—	1,582	811
Average common shares outstanding for diluted computation	116,196	112,726	115,275	113,295

Comprehensive Income. Comprehensive income (loss) comprises net income (loss) 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.

Reclassifications. We have reclassified certain prior-year period balances to conform to the current-period presentation.

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 $4.7 for the nine months ended June 30, 2012.

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

3. Accounting Changes
New Accounting Standards Not Yet Adopted
Disclosures about Reclassifications Out of Accumulated Other Comprehensive Income. In February 2013, the Financial Accounting Standards Board ("FASB") issued new accounting guidance regarding disclosures for items reclassified out of accumulated other comprehensive income ("AOCI"). The new disclosure guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2012. The new disclosures are to be applied prospectively, and early adoption is permitted. We expect to adopt the new guidance in Fiscal 2014. As this guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.
Disclosures about Offsetting Assets and Liabilities. In December 2011 (and amended in January 2013), the FASB issued new accounting guidance requiring entities to disclose both gross and net information about recognized derivative instruments that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on 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, and is required to be applied retrospectively. As this guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.

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:

	Nine Months Ended June 30,	
	2013 (As Reported)	2012 Pro Forma
Revenues	$5,932.6	$5,885.2
Net income attributable to UGI Corporation	$289.2	$211.4
Earnings per common share attributable to UGI Corporation stockholders:		
Basic	$2.54	$1.88
Diluted	$2.51	$1.87

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

5. Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	June 30, 2013	September 30, 2012	June 30, 2012
Goodwill (not subject to amortization)	$2,834.0	$2,818.3	$2,756.0
Intangible assets:			
Customer relationships, noncompete agreements and other	$692.6	$691.9	$689.3
Trademarks and tradenames (not subject to amortization)	128.4	137.2	189.6
Gross carrying amount	821.0	829.1	878.9
Accumulated amortization	(212.4)	(170.9)	(161.2)
Intangible assets, net	$608.6	$658.2	$717.7

The decrease in trademarks and tradenames and the increase in goodwill during the nine months ended June 30, 2013, principally reflects a correcting adjustment associated with the Heritage Acquisition. Amortization expense of intangible assets was $13.3 and $40.2 for the three and nine months ended June 30, 2013, respectively, and $12.4 and $31.2 for the three and nine months ended June 30, 2012, respectively. No amortization is included in cost of sales in the Condensed Consolidated Statements of Income. As of June 30, 2013, 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 — $12.5; Fiscal 2014 — $50.5; Fiscal 2015 — $47.4; Fiscal 2016 — $41.3; Fiscal 2017 — $35.0.

6. Segment Information

Our operations comprise six reportable segments generally based upon products sold, geographic location and regulatory environment. Our reportable segments comprise: (1) AmeriGas Propane; (2) an international LPG segment comprising Antargaz; (3) an international LPG segment principally comprising Flaga and AvantiGas; (4) Gas Utility; (5) Energy Services; and (6) Electric Generation. We refer to both international segments together as “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 and nine months ended June 30, 2012 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.

Three Months Ended June 30, 2013:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$1,372.3	$(61.5)(c)	$581.7	$126.7	$233.0	$15.7	$249.2	$182.5	$45.0
Cost of sales	$827.9	$(60.1)(c)	$305.7	$52.4	$213.9	$7.7	$148.7	$134.8	$24.8
Segment profit:									
Operating income (loss)	$53.1	$(0.2)	$6.6	$16.1	$7.4	$0.8	$14.5	$6.5	$1.4
Income from equity investees	—	—	—	—	—	—	—	—	—
Interest expense	(59.2)	—	(41.2)	(9.2)	(0.6)	—	(6.2)	(1.2)	(0.8)
(Loss) income before income taxes	$(6.1)	$(0.2)	$(34.6)	$6.9	$6.8	$0.8	$8.3	$5.3	$0.6
Partnership EBITDA (a)			$59.1						
Noncontrolling interests’ net income (loss)	$(29.8)	$—	$(29.6)	$—	$—	$—	$(0.3)	$0.1	$—
Depreciation and amortization	$91.9	$(0.1)	$52.5	$13.1	$2.1	$2.6	$14.0	$6.1	$1.6
Capital expenditures	$107.6	$(0.1)	$26.3	$37.3	$22.0	$4.4	$11.7	$4.0	$2.0

Total assets (at period end)	$9,828.8	$(95.9)	$4,388.1	$2,164.4	$437.0	$267.2	$1,771.7	$543.1	$353.2
Bank loans (at period end)	$135.9	$—	$80.0	$—	$45.5	$—	$—	$10.4	$—
Goodwill (at period end)	$2,834.0	$—	$1,929.2	$182.1	$2.8	$—	$619.2	$93.7	$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 June 30, 2012:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$1,277.2	$(33.4)(c)	$571.9	$122.3	$157.0	$10.9	$211.8	$193.4	$43.3
Cost of sales	$810.2	$(32.1)(c)	$334.0	$51.4	$140.0	$6.4	$133.6	$153.0	$23.9
Segment profit:									
Operating (loss) income	$(19.2)	$—	$(48.4)	$22.5	$6.8	$(1.9)	$(1.2)	$2.4	$0.6
Income from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Gain on extinguishments of debt	0.1	—	0.1	—	—	—	—	—	—
Interest expense	(61.3)	—	(41.8)	(9.9)	(1.2)	—	(6.3)	(1.2)	(0.9)
(Loss) income before income taxes	$(80.5)	$—	$(90.1)	$12.6	$5.6	$(1.9)	$(7.6)	$1.2	$(0.3)
Partnership EBITDA (a)			$1.8						
Noncontrolling interests' net loss	$(70.2)	$—	$(70.0)	$—	$—	$—	$(0.2)	$—	$—
Depreciation and amortization	$84.6	$—	$49.5	$12.3	$0.9	$2.3	$13.5	$4.7	$1.4
Capital expenditures	$83.7	$—	$25.2	$29.0	$7.3	$6.3	$12.0	$2.8	$1.1
Total assets (at period end)	$9,652.2	$(87.4)	$4,579.5	$2,027.0	$355.0	$261.3	$1,664.7	$513.2	$338.9
Bank loans (at period end)	$187.3	$—	$68.8	$—	$95.0	$—	$—	$23.5	$—
Goodwill (at period end)	$2,756.0	$—	$1,866.7	$182.1	$2.8	$—	$605.0	$92.4	$7.0

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

Three Months Ended June 30,	2013	2012
Partnership EBITDA	$59.1	1.8
Depreciation and amortization	(52.5)	(49.5)
Gain on extinguishments of debt	—	(0.1)
Noncontrolling interests (i)	—	(0.6)
Operating income (loss)	$6.6	$(48.4)

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

(b) Corporate & Other results principally comprise Electric Utility, Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses ("HVAC/R"), net expenses of UGI's captive general liability insurance company and UGI'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.

- 11 -

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

Nine Months Ended June 30, 2013:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$5,932.6	$(181.1) (c)	$2,634.6	$743.6	$764.8	$ 47.7	$1,121.1	$659.0	$ 142.9
Cost of sales	$3,547.3	$(176.2) (c)	$1,370.2	$372.7	$648.8	$ 27.9	$714.4	$507.1	$ 82.4
Segment profit:									
Operating income	$835.4	$(1.1)	$403.9	$191.6	$78.2	$ 1.5	$129.8	$30.6	$ 0.9
Income from equity investees	0.1	—	—	—	—	—	0.1	—	—
Interest expense	(179.6)	—	(124.2)	(28.1)	(2.4)	—	(19.0)	(3.8)	(2.1)
Income (loss) before income taxes	$655.9	$(1.1)	$279.7	$163.5	$75.8	$ 1.5	$110.9	$26.8	$ (1.2)
Partnership EBITDA (a)			$550.5						
Noncontrolling interests’ net income	$192.6	$—	$192.4	$—	$—	$ —	$0.1	$0.1	$ —
Depreciation and amortization	$266.3	$(0.1)	$150.5	$38.4	$5.6	$ 7.5	$42.3	$17.4	$ 4.7
Capital expenditures	$292.5	$(1.1)	$80.7	$90.2	$54.8	$ 15.4	$37.1	$10.3	$ 5.1
Total assets (at period end)	$9,828.8	$(95.9)	$4,388.1	$2,164.4	$437.0	$ 267.2	$1,771.7	$543.1	$ 353.2
Bank loans (at period end)	$135.9	$—	$80.0	$—	$45.5	$ —	$—	$10.4	$ —
Goodwill (at period end)	$2,834.0	$—	$1,929.2	$182.1	$2.8	$ —	$619.2	$93.7	$ 7.0

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Nine Months Ended June 30, 2012:

					Midstream & Marketing		International Propane		
	Total	Elims.	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$5,393.5	$(134.2)(c)	$2,411.3	$696.8	$652.5	$ 27.1	$958.7	$646.5	$ 134.8
Cost of sales	$3,438.6	$(130.7)(c)	$1,447.8	$370.6	$553.1	$ 17.6	$597.9	$506.3	$ 76.0
Segment profit:									
Operating income (loss)	$549.9	$—	$206.7	$168.7	$67.3	$ (7.9)	$96.3	$16.8	$ 2.0
Loss from equity investees	(0.2)	—	—	—	—	—	(0.2)	—	—
Loss on extinguishments of debt	(13.3)	—	(13.3)	—	—	—	—	—	—
Interest expense	(162.6)	—	(103.4)	(30.1)	(3.6)	—	(19.7)	(3.4)	(2.4)
Income (loss) before income taxes	$373.8	$—	$90.0	$138.6	$63.7	$ (7.9)	$76.4	$13.4	$ (0.4)
Partnership EBITDA (a)			$310.0						
Noncontrolling interests' net income	$46.5	$—	$46.2	$—	$—	$ —	$0.3	$—	$ —
Depreciation and amortization	$227.7	$—	$118.5	$36.6	$2.4	$ 6.6	$42.6	$16.6	$ 4.4
Capital expenditures	$237.7	$—	$70.3	$76.5	$30.2	$ 17.4	$28.0	$11.5	$ 3.8
Total assets (at period end)	$9,652.2	$(87.4)	$4,579.5	$2,027.0	$355.0	$ 261.3	$1,664.7	$513.2	$ 338.9
Bank loans (at period end)	$187.3	$—	$68.8	$—	$95.0	$ —	$—	$23.5	$ —
Goodwill (at period end)	$2,756.0	$—	$1,866.7	$182.1	$2.8	$ —	$605.0	$92.4	$ 7.0

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

Nine Months Ended June 30,	2013	2012
Partnership EBITDA	$550.5	$310.0
Depreciation and amortization	(150.5)	(118.5)
Loss on extinguishments of debt	—	13.3
Noncontrolling interests (i)	3.9	1.9
Operating income	$403.9	$206.7

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

(b) Corporate & Other results principally comprise Electric Utility, Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses ("HVAC/R"), net expenses of UGI's captive general liability insurance company and UGI'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.

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

7. Energy Services Accounts Receivable Securitization Facility

Energy Services currently has a $100 receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper that expires in November 2013. 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 nine months ended June 30, 2013 and 2012, Energy Services transferred trade receivables to ESFC totaling $766.1 and $674.4, respectively. During the nine months ended June 30, 2013 and 2012, ESFC sold an aggregate $224.0 and $266.5, respectively, of undivided interests in its trade receivables to the commercial paper conduit. At June 30, 2013, the outstanding balance of ESFC receivables was $58.2 and there was $9.5 sold to the commercial paper conduit. At June 30, 2012, the outstanding balance of ESFC receivables was $41.0 and there was $10.0 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:

	June 30, 2013	September 30, 2012	June 30, 2012
Regulatory assets:			
Income taxes recoverable	$104.7	$103.2	$99.9
Underfunded pension and postretirement plans	177.8	188.2	144.6
Environmental costs	16.6	16.8	16.6
Deferred fuel and power costs	4.1	11.6	9.8
Removal costs, net	12.1	12.7	11.8
Other	5.6	5.9	8.3
Total regulatory assets	$320.9	$338.4	$291.0
Regulatory liabilities:			
Postretirement benefits	$14.2	$13.1	$12.3
Environmental overcollections	2.9	2.9	3.7
Deferred fuel and power refunds	14.2	4.4	10.3
State tax benefits—distribution system repairs	8.0	7.4	7.0
Other	0.7	0.5	0.7
Total regulatory liabilities	$40.0	$28.3	$34.0

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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. Net unrealized gains (losses) on such contracts at June 30, 2013, September 30, 2012 and June 30, 2012 were $(1.4), $5.3 and $0.3, 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 Condensed Consolidated Balance Sheets with an associated adjustment to regulatory assets or liabilities in accordance with GAAP related to rate-regulated entities. At June 30, 2013, September 30, 2012, and June 30, 2012, the fair values of Electric Utility's electricity supply contracts were net losses of $6.1, $9.2 and $13.1, 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 June 30, 2013, September 30, 2012, and June 30, 2012, 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, 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. On February 19, 2013, the PUC entered a final order (the "Final Order") in which PUC Commissioners adopted the Joint Settlement, with certain modifications. The Final Order requires 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. The Final Order makes no findings that UGI Utilities has violated any regulation or operating procedure. The Company does not believe that the cost of complying with the requirements of the Final Order will have a material impact on UGI Utilities' consolidated financial position, results of operations or cash flows.
Transfers of Assets. On February 1, 2012, CPG filed an application with the PUC for review and approval of the transfer of an 11-mile natural gas pipeline, related facilities and right of way located in Delmar Township, Pennsylvania ("TL-96 line") to Energy Services. The PUC approved the transfer and, in April 2013, the TL-96 line was dividended to UGI and subsequently contributed to Energy Services. The net book value of the TL-96 line is approximately $2.6.

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2013	2012	2013	2012
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)	(0.1)
Actuarial loss	3.7	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 Benefits		Other Postretirement Benefits	
	Nine Months Ended June 30,		Nine Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$8.5	$6.4	$0.5	$0.3
Interest cost	17.6	18.3	0.7	0.8
Expected return on assets	(20.7)	(19.2)	(0.4)	(0.4)
Amortization of:				
Prior service cost (benefit)	0.2	0.2	(0.2)	(0.3)
Actuarial loss	11.2	6.3	0.3	0.3
Net benefit cost	16.8	12.0	0.9	0.7
Change in associated regulatory liabilities	—	—	2.4	2.3
Net expense	$16.8	$12.0	$3.3	$3.0

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 $2.5 to the Pension Plan during the remainder of Fiscal 2013. During the nine months ended June 30, 2013 and 2012, the Company made cash contributions to the Pension Plan of $13.4 and $25.4, 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 nine months ended June 30, 2013 and 2012, 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 ("Supplemental Defined Benefit Plans"). We recorded pre-tax expense associated with these plans of $0.8 and $0.6 for the three months ended June 30, 2013 and 2012, respectively. We recorded pre-tax expense associated with these plans of $2.4 and $2.1 for the nine months ended June 30, 2013 and 2012, respectively. During the nine months ended June 30, 2013, the

Company made payments with respect to the Supplemental Defined Benefit Plans totaling $20.6, including $20.0 used to fund trusts established by the Company for Supplemental Defined Benefit Plan participants who chose to defer payment upon retirement.

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.

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 June 30, 2013 and 2012, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $14.4 and $15.8, 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 June 30, 2013, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material.
From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by it or owned or operated by its former subsidiaries. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by former subsidiaries of UGI Utilities if a court were to conclude that (1) the

subsidiary’s separate corporate form should be disregarded or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary’s MGP.

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. There have been no recent developments in this matter.

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. There have been no recent developments in this matter. 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

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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. 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. Effective June 20, 2013, we entered into a settlement agreement with BP and the lawsuit has been dismissed. The effect of the settlement agreement will not have a material impact on our results of operations or 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 June 30, 2013, September 30, 2012 and June 30, 2012:

	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
June 30, 2013:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$2.2	$7.4	$—	$9.6
Foreign currency contracts	$—	$1.0	$—	$1.0
Interest rate contracts	$—	$8.1	$—	$8.1
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$(8.0)	$(24.1)	$—	$(32.1)
Foreign currency contracts	$—	$(1.7)	$—	$(1.7)
Interest rate contracts	$—	$(46.9)	$—	$(46.9)
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)
June 30, 2012:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$5.1	$12.3	$—	$17.4
Foreign currency contracts	$—	$7.1	$—	$7.1
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$(18.0)	$(102.0)	$—	$(120.0)
Interest rate contracts	$—	$(67.0)	$—	$(67.0)

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 designated as Level 2 are based upon indicative price quotations available through brokers, industry price publications or recent market transactions and related market indicators. For commodity option contracts designated as Level 2 which are not traded on an exchange, we use a Black Scholes option pricing model that considers time value and volatility of the underlying commodity. The fair values of our Level 2 interest rate contracts and foreign currency contracts are based upon third-party quotes or indicative values based on recent market transactions. There were no transfers between Level 1 and Level 2 during the periods presented.

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. At June 30, 2013, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,493.8 and $3,621.0, respectively. At June 30, 2012, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,561.2 and $3,730.7, 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 June 30, 2013 and 2012, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 11.7 million dekatherms and 13.2 million dekatherms, respectively. At June 30, 2013, the maximum period over which Gas Utility is hedging natural gas market price risk is 16 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 June 30, 2013 and 2012, the fair values of Electric Utility's forward purchase power agreements comprising losses of $6.1 and $13.1, 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 June 30, 2013 and 2012, the volumes of Electric Utility's forward electricity purchase contracts was 327.4 million kilowatt hours and 654.7 million kilowatt hours, respectively. At June 30, 2013, the maximum period over which these contracts extend is 11 months.

In order to reduce volatility associated with a substantial portion of its electricity transmission congestion costs, Electric Utility obtains FTRs through an annual allocation process 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 June 30, 2013 and 2012, the volumes associated with Electric Utility FTRs totaled 260.6 million kilowatt hours and 261.0 million kilowatt hours, respectively. Midstream & Marketing's FTRs are recorded at fair value with changes in fair value reflected in cost of sales. At June 30, 2013 and 2012, the volumes associated with Midstream & Marketing's FTRs totaled 1,609.2 million kilowatt hours and 1,285.5 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 futures contracts, IntercontinentalExchange ("ICE") natural gas basis swap contracts, and electricity futures contracts. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to hedge the price of a portion of its anticipated future sales of electricity from its electric generation facilities. In addition, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later 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 June 30, 2013, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 2.7 million dekatherms and 1.8 million gallons, respectively. At June 30, 2012, the volumes associated with Midstream & Marketing's natural gas and propane storage NYMEX contracts totaled 4.1 million dekatherms and 2.2 million gallons, respectively.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures and swap contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment. Associated volumes, fair values and effects on net income were not material for all periods presented.

At June 30, 2013 and 2012, we had the following outstanding derivative commodity instruments volumes that qualify for hedge accounting treatment:

	Volumes
	June 30,

Commodity	2013	2012
LPG (millions of gallons)	236.7	231.9
Natural gas (millions of dekatherms)	19.4	21.2
Electricity forward purchase contracts (millions of kilowatt-hours)	927.2	1688.4
Electricity forward sales contracts (millions of kilowatt-hours)	451.0	131.8

At June 30, 2013, the maximum period over which we are hedging our exposure to the variability in cash flows associated with LPG commodity price risk is 19 months with a weighted average of 7 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 10 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 27 months for electricity forward purchase contracts, with a weighted average of 9 months, and 14 months for electricity forward sales contracts, with a weighted average of 3 months. At June 30, 2013, the maximum period over which we are economically hedging electricity congestion with FTRs (excluding Electric Utility) is 11 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 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 June 30, 2013, 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 $15.6.

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 June 30, 2013 and 2012, the total notional amount of existing variable-rate debt subject to interest rate swap agreements was €440.5 and €441.9, respectively.

Our domestic businesses' long-term debt is typically issued at fixed rates of interest. As these long-term debt issues mature, we typically refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce market rate risk on the underlying benchmark rate of interest associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs"). At June 30, 2013 and 2012, 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.

UGI Utilities reclassified pre-tax losses of $0.7 from AOCI into income during the nine months ended June 30, 2012, as a result of the discontinuance of cash flow hedge accounting for a portion of expected interest payments associated with the issuance of long-term debt originally anticipated to occur in September 2012. Such losses are included in other income, net, on the Condensed Consolidated Statements of Income.

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 June 30, 2013, the amount of net losses associated with interest rate hedges (excluding pay-fixed, receive-variable interest rate swaps) expected to be reclassified into earnings during the next twelve months is $2.2.

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 June 30, 2013 and 2012, we were hedging a total of $170.3 and $75.0 of U.S. dollar-denominated LPG purchases, respectively. At June 30, 2013, the maximum period over which we are hedging our exposure to the variability in cash flows associated with dollar-denominated purchases of LPG is 33 months with a weighted average of 14 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 June 30, 2013, we had no euro-denominated net investment hedges. At June 30, 2012, 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. At June 30, 2013, the fair values of these foreign currency contracts were not material.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

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 June 30, 2013, 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 $1.0. 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 forms of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2013 and 2012, restricted cash in brokerage accounts totaled $6.0 and $7.6, 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 June 30, 2013. Certain of the Partnership's derivative contracts have credit-risk-related contingent features that may require the posting of additional collateral in the event of a downgrade of the Partnership's debt rating. At June 30, 2013, 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 June 30, 2013 and 2012:

	Derivative Assets Balance Sheet Location	Fair Value June 30, 2013	2012	Derivative (Liabilities) Balance Sheet Location	Fair Value June 30, 2013	2012
Derivatives Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments and Other assets	$7.5	$4.2	Derivative financial instruments and Other noncurrent liabilities	$(24.4)	$(95.5)
Foreign currency contracts	Derivative financial instruments and Other assets	1.0	7.1	Other noncurrent liabilities	(0.4)	—
Interest rate contracts	Derivative financial instruments	8.1	—	Derivative financial instruments	(46.9)	(67.0)

				and Other noncurrent liabilities		
Total Derivatives Designated as Hedging Instruments		$16.6	$11.3		$(71.7)	$(162.5)
Derivatives Subject to Utility Rate Regulation:						
Commodity contracts	Derivative financial instruments	$0.1	$0.6	Derivative financial instruments and Other noncurrent liabilities	$(7.6)	$(13.4)
Derivatives Not Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments	$2.0	$12.6	Derivative financial instruments	$(0.1)	$(11.1)
Foreign currency contracts	Derivative financial instruments	—	—	Derivative financial instruments	(1.3)	—
Total Derivatives		$18.7	$24.5		$(80.7)	$(187.0)

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
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 June 30, 2013 and 2012:

Three Months Ended June 30,	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
	2013	2012	2013	2012	
Cash Flow Hedges:					
Commodity contracts	$(22.8)	$(59.3)	$(6.9)	$(31.0)	Cost of sales
Foreign currency contracts	(0.3)	3.1	—	—	Cost of sales
Interest rate contracts	14.0	(16.6)	(3.6)	(3.3)	Interest expense / other income, net
Total	$(9.1)	$(72.8)	$(10.5)	$(34.3)	
Net Investment Hedges:					
Foreign currency contracts	$—	$0.9			

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
	2013	2012	
Commodity contracts	$2.0	$(15.9)	Cost of sales
Commodity contracts	(0.1)	(0.1)	Operating expenses / other income, net
Foreign currency contracts	(0.9)	—	Other income, net
Total	$1.0	$(16.0)	

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 nine months ended June 30, 2013 and 2012:

Nine Months Ended June 30,	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
	2013	2012	2013	2012	
Cash Flow Hedges:					
Commodity contracts	$(28.1)	$(166.2)	$(64.1)	$(94.4)	Cost of sales
Foreign currency contracts	(1.4)	2.8	(0.1)	2.0	Cost of sales
Interest rate contracts	23.0	(29.0)	(10.6)	(8.4)	Interest expense / other income, net

Total	$(6.5)	$(192.4)	$(74.8)	$(100.8)
Net Investment Hedges:				
Foreign currency contracts	$—	$0.9		

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Derivatives Not Designated as Hedging Instruments:	2013	2012	
Commodity contracts	$2.4	$(12.6)	Cost of sales
Commodity contracts	—	0.1	Operating expenses / other income, net
Foreign currency contracts	(1.1)	0.5	Other income, net
Total	$1.3	$(12.0)	

The amounts of derivative gains or losses representing ineffectiveness were not material for the three and nine month periods ended June 30, 2013 and 2012.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

We are also a party to a number of other contracts that have elements of a derivative instrument. These contracts include, among others, binding purchase orders 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:

	June 30, 2013	September 30, 2012	June 30, 2012
Non-utility LPG and natural gas	$194.6	$240.7	$220.1
Gas Utility natural gas	43.1	57.7	27.8
Materials, supplies and other	66.3	58.5	69.4
Total inventories	$304.0	$356.9	$317.3

At June 30, 2013, UGI Utilities is a party to three principal storage contract administrative agreements (“SCAAs”), one of which expires in October 2013 and two of which expire in October 2015. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the 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 June 30, 2013, UGI Utilities’ principal SCAAs are with Energy Services. The carrying values of natural gas storage inventories released under SCAAs with non-affiliates at September 30, 2012 and June 30, 2012, comprising 3.8 billion cubic feet (“bcf”) and 1.9 bcf of natural gas, were $11.4 and $5.3, respectively.

15. Error in Accounting For Certain Customer Credits

During the three months ended March 31, 2013, the Partnership identified an error in accounting for certain customer credits. The Partnership determined that the recording of propane revenues did not appropriately consider the effects of certain customer credits which were recorded when issued in a subsequent period. As a result, beginning January 1, 2013, the Partnership changed its accounting for customer credits to record an estimate of such credits at the time propane revenues are recorded. Such estimate considers the Partnership’s history of providing credits, propane revenue activity and other factors. The Company has evaluated the impact of the error on prior periods and has determined that the effect is not material to any prior period financial statements. The Company has also evaluated and concluded that the impact of recording the cumulative effect of the correction of the error as of January 1, 2013, is not material to the financial statements for the three and six months ended March 31, 2013, nor is it expected to be material to the financial statements for Fiscal 2013. The correction of the error in accounting for customer credits had the effect of increasing revenues and accounts receivable by $3.6, and increasing net income attributable to UGI Corporation by

$0.6, for the three months ended June 30, 2013, and decreasing revenues and accounts receivable by $5.1, and decreasing net income attributable to UGI Corporation by $0.9, for the nine months ended June 30, 2013. If the Company had corrected the error in its method of accounting and recorded the estimate of credits as of September 30, 2012, the cumulative effect of the change as of that date would have decreased net income attributable to UGI Corporation by approximately $0.7.

Table of Contents

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.

UGI CORPORATION AND SUBSIDIARIES

ANALYSIS OF RESULTS OF OPERATIONS
The following analyses compare our results of operations for the three months ended June 30, 2013 (“2013 three-month period”) with the three months ended June 30, 2012 (“2012 three-month period”) and the nine months ended June 30, 2013 (“2013 nine-month period”) with the nine months ended June 30, 2012 (“2012 nine-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 $14.7 million for the 2013 three-month period compared to net loss attributable to UGI Corporation of $(6.3) million for the prior-year three-month period. Operating results in the 2013 three-month period include higher net income from our European LPG businesses and a significantly lower seasonal net loss from AmeriGas Propane. Each of our International Propane business units’ results during the 2013 three-month period improved from the prior-year three-month period with the most significant year-over-year increase at Antargaz. The improved results at Antargaz reflect higher volumes from colder spring weather and the benefit of higher average unit margins. At AmeriGas Propane, average temperatures during the 2013 three-month period were approximately normal but were significantly colder than the prior year. The lower seasonal loss from AmeriGas Propane includes the colder weather’s impact on retail propane volumes sold, higher average retail unit margins and lower operating and administrative expenses reflecting in large part the benefits from the integration of Heritage Propane. Midstream & Marketing’s results in the 2013 three-month period principally reflect higher income from its Electric Generation business segment and greater income from Energy Service’s storage, capacity management and peaking activities offset in part by lower retail power total margin. During the 2013 three-month period, Gas Utility total margin was slightly higher than the prior year on colder weather and customer additions, but the increase in margin was more than offset by higher Gas Utility operating and administrative expenses.
We recorded net income attributable to UGI Corporation of $289.2 million for the 2013 nine-month period compared to $214.1 million for the prior-year nine-month period. Operating results in the prior-year nine-month period were negatively affected by heating-degree day temperatures that were substantially warmer than normal across all of our business units. Operating results in the 2013 nine-month period were higher at each of our businesses due to the colder weather and, with respect to AmeriGas Propane, the full-period effects of the operations of Heritage Propane acquired January 12, 2012. Notwithstanding average temperatures that were approximately 4.1% warmer than normal, net income attributable to UGI from AmeriGas Propane increased $26.8 million principally reflecting year-over-year weather that was nearly 16.8% colder than the prior year and the full-period benefit of Heritage Propane acquired January 12, 2012. The return to more normal weather in the 2013 nine-month period from the record-setting warm weather experienced in the prior-year resulted in greater AmeriGas Propane retail volumes sold and higher total retail propane margin. Gas Utility results improved significantly from the prior year reflecting the effects of the colder 2013 nine-month period weather and, to a much lesser extent, customer growth due principally to customer conversions from oil. Midstream & Marketing’s Energy Services business segment results in the 2013 nine-month period also benefited from the effects of colder weather on natural gas marketing activities and midstream asset opportunities, while Midstream & Marketing’s Electric Generation business segment results benefited from higher volumes and increased electricity spot market prices. The improved Electric Generation volumes during the 2013 nine-month period reflect the full availability of our Hunlock Creek electricity generating station and greater production from the Conemaugh electricity generating station in which we own a 5.97% interest.
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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

2013 three-month period compared to the 2012 three-month period

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

	Three Months Ended June 30,					
	2013		2012		Variance - Favorable (Unfavorable)	
(Millions of dollars)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane	$(2.9)	(19.7)%	$(12.3)	195.2%	$9.4	76.4%
International Propane	8.4	57.1%	(8.1)	128.6%	16.5	N.M.
Gas Utility	4.1	27.9%	7.0	(111.1)%	(2.9)	(41.4)%
Midstream & Marketing	4.6	31.3%	2.5	(39.7)%	2.1	84.0%
Corporate & Other	0.5	3.4%	4.6	(73.0)%	(4.1)	N.M.
Net income (loss) attributable to UGI Corporation	$14.7	100.0%	$(6.3)	100.0%	$21.0	N.M

N.M. — Variance is not meaningful.

AmeriGas Propane:

For the three months ended June 30,	2013	2012	Increase	
(Millions of dollars)				
Revenues	$581.7	$571.9	$9.8	1.7%
Total margin (a)	$276.0	$237.9	$38.1	16.0%
Partnership EBITDA (b)	$59.1	$1.8	$57.3	N.M.
Operating income (loss)(b)	$6.6	$(48.4)	$55.0	N.M.
Retail gallons sold (millions)	224.7	204.0	20.7	10.1%
Degree days—% colder (warmer) than normal (c)	0.5%	(23.8)%	—	—

N.M. - Variance is not meaningful.

(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 June 30, 2013 and 2012, includes transition expenses of $9.9 million and $15.0 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.

AmeriGas Propane’s retail gallons sold in the 2013 three-month period increased more than 10% from the 2012 three-month period reflecting average temperatures based upon heating degree days that were approximately normal but significantly colder than the prior-year three-month period. Based upon heating degree-day data, temperatures in the Partnership’s service territories during the 2013 three-month period averaged approximately 0.5% colder than normal while temperatures in the prior-year period averaged approximately 23.8% warmer than normal.

Retail propane revenues increased $9.4 million during the 2013 three-month period reflecting the higher retail volumes sold ($49.9 million) offset in large part by the effects of a decline in average retail selling prices ($40.5 million) which were the result of lower propane product costs. Wholesale propane revenues increased $1.5 million for the 2013 three-month period on slightly higher wholesale sales. Average daily wholesale propane commodity prices during the 2013 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 7% lower than such prices during the prior-year three-month period. Total revenues from fee income and other ancillary sales and services in the 2013 three-month period were slightly lower than in the 2012 three-month period. Total cost of sales decreased $28.3 million principally reflecting the effects on retail propane cost of sales of the lower average propane product costs ($60.1 million) partially offset by effects of the greater retail volumes sold ($30.0 million).

Total margin increased $38.1 million in the 2013 three-month period principally reflecting higher retail propane total margin ($39.4 million). The increase in retail propane total margin reflects the increase in retail volumes sold and modestly higher average retail propane unit margins.

Partnership EBITDA in the 2013 three-month period increased $57.3 million principally reflecting the higher total margin ($38.1 million) and lower operating and administrative expenses ($18.5 million) reflecting, among other things, synergies from the integration of Heritage Propane, lower self-insured liability and casualty expenses ($7.2 million) and lower Heritage Propane integration transition expenses. Operating and administrative expenses in the 2013 three-month period include $9.9 million of transition expenses associated with the integration of Heritage Propane while operating and administrative expenses in the prior-year period include Heritage Propane acquisition and transition expenses of $15.0 million. Operating income increased $55.0 million in the 2013 three-month period principally reflecting the higher total margin ($38.1 million) and the lower operating and administrative expenses ($18.5 million) partially offset by increased depreciation and amortization expense ($3.0 million).

International Propane:

For the three months ended June 30,	2013		2012		Increase		
(Millions of dollars)							
Revenues	$431.7		$405.2		$26.5	6.5	%
Total margin (a)	$148.2		$118.6		$29.6	25.0	%
Operating income	$21.0		$1.2		$19.8	N.M	
Income (loss) before income taxes	$13.6		$(6.4	)	$20.0	N.M	
Retail gallons sold (b)	126.6		119.0		7.6	6.4	%
Antargaz degree days—% colder (warmer) than normal (c)	19.7	%	(3.5	)%	—	—	
Flaga degree days—% (warmer) than normal (c)	(7.2	)%	(20.4	)%	—	—	

N.M -Variance is not meaningful.

(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 and Flaga service territories.

Based upon heating degree day data, temperatures in our International Propane LPG operations were colder than normal at Antargaz and AvantiGas, and modestly warmer than normal at our Flaga business unit. Notwithstanding the variances to normal weather, our European LPG businesses experienced spring weather that was significantly colder than the prior-year three-month period. The colder spring weather increased retail LPG volumes sold by 6.4%. During the 2013 three-month period, the average wholesale commodity price for propane in northwest Europe was approximately 6% lower than in the prior-year period while the average wholesale commodity price for butane was approximately 8% lower than the prior-year period.

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 2013 and 2012 three-month periods, the average un-weighted translation rate was approximately $1.30 and $1.29 per euro, respectively. The difference in euro to U.S. dollar translation rates did not have a material impact on net income attributable to UGI.

International Propane revenues were $26.5 million greater than the prior-year period as the effects on revenues from the greater retail LPG volumes sold, greater wholesale volumes sold and, to a much lesser extent, increased revenues from natural gas marketing activities at Antargaz were partially offset by the effects of lower average LPG wholesale commodity prices principally at Flaga. Cost of sales decreased to $283.5 million in the 2013 three-month period from $286.6 million in the prior-year period, as the effects of the lower LPG wholesale commodity prices principally at Flaga were largely offset by the effects of the increase in retail and wholesale gallons sold and higher cost of sales associated with natural gas marketing activities at Antargaz.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

Total International Propane margin increased $29.6 million during the 2013 three-month period principally reflecting the effects of higher average retail LPG unit margins principally at Antargaz and, to a lesser extent, the effects of the greater retail volumes sold.
International Propane operating income and income before income taxes were $19.8 million and $20.0 million higher than the prior-year period, respectively, principally reflecting the higher total margin ($29.6 million) partially offset by increased operating and administrative costs, principally at Antargaz ($6.2 million), and slightly higher International Propane depreciation expense. Antargaz operating and administrative costs in the 2013 three-month period include greater incentive compensation and benefits costs and greater delivery expenses. International Propane operating expenses in the prior-year three-month period include $1.4 million of transition expenses associated with LPG businesses acquired from Shell in October 2012.

Gas Utility:

For the three months ended June 30,	2013	2012	Increase (Decrease)	
(Millions of dollars)				
Revenues	$126.7	$122.3	$4.4	3.6 %
Total margin (a)	$74.3	$70.9	$3.4	4.8 %
Operating income	$16.1	$22.5	$(6.4)	(28.4)%
Income before income taxes	$6.9	$12.6	$(5.7)	(45.2)%
System throughput—billions of cubic feet ("bcf") —				
Core market	8.8	8.3	0.5	6.0 %
Total	35.9	36.2	(0.3)	(0.8)%
Degree days—% (warmer) than normal (b)	(7.1)%	(19.0)%	—	—

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

Temperatures in the Gas Utility service territory in the 2013 three-month period based upon heating degree days were 7.1% warmer than normal but 14.4% colder than the prior-year three-month period. Total distribution system throughput decreased slightly, notwithstanding increases in core market and large firm delivery service throughput, principally reflecting lower throughput to certain low-margin, 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, due principally to conversions from oil prompted by sustained lower natural gas prices and high oil prices.

Gas Utility revenues increased $4.4 million during the 2013 three-month period principally reflecting higher revenues from core market customers ($1.9 million), greater revenues from large firm delivery service customers on the higher throughput, and slightly higher revenues from off-system sales ($1.5 million). The increase in core market revenues principally reflects the effects of the higher core market volumes partially offset by the effects of lower average purchased gas cost ("PGC") rates resulting from lower natural gas prices ($7.0 million). 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 $52.4 million in the 2013 three-month period compared with $51.4 million in the prior-year period principally reflecting the effects of the greater retail core-market volumes sold ($6.3 million) and the higher off-system sales

($1.5 million) partially offset by the effects of the lower average PGC rates.
Gas Utility total margin increased $3.4 million in the 2013 three-month period principally reflecting higher core market total margin ($1.3 million) and greater large firm delivery service total margin ($1.7 million). The higher core market and large firm delivery service total margin reflects the effects of the greater throughput to these customers.

The decreases in Gas Utility operating income and income before income taxes during the 2013 three-month period, notwithstanding the increase in total margin, principally reflects higher operating and administrative expenses ($9.4 million) including, among other things, higher uncollectible accounts expense ($2.4 million), higher pension and benefits expenses ($1.8 million) and higher injuries and damages and distribution system expenses ($1.4 million).

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

Midstream & Marketing:

For the three months ended June 30,	2013	2012	Increase		
(Millions of dollars)					
Revenues (a)	$247.8	$166.7	$81.1	48.7	%
Total margin (b)	$27.1	$21.5	$5.6	26.0	%
Operating income	$8.2	$4.9	$3.3	67.3	%
Income before income taxes	$7.6	$3.7	$3.9	105.4	%

(a) Amounts are net of intercompany revenues between Midstream & Marketing’s Energy Services and Electric Generation segments.
(b) Total margin represents total revenues less total cost of sales.

Midstream & Marketing total revenues increased $81.1 million in the 2013 three-month period principally reflecting higher natural gas revenues ($76.8 million) principally from greater natural gas volumes and, to a much lesser extent, greater Electric Generation revenues ($4.7 million). The increase in natural gas revenues principally reflects higher wholesale volumes sold and higher average selling prices for natural gas, while the increase in Electric Generation revenues reflects higher average electricity prices and higher electricity output at the Hunlock Creek electricity generating station.

Midstream & Marketing total margin increased $5.6 million in the 2013 three-month period principally reflecting higher Electric Generation total margin ($3.4 million) and increased peaking, capacity management and storage total margin ($4.7 million) partially offset by lower retail power total margin. The greater total margin from Electric Generation principally reflects the impact of higher electricity prices on electricity unit margins and, to a lesser extent, greater electricity production principally from our Hunlock Creek natural gas-fired electricity generating station. In the prior-year three-month period, the Hunlock Creek electricity generating station was operating at less than full capacity.

Midstream & Marketing operating income in the 2013 three-month period was $3.3 million higher than the prior-year period reflecting the previously mentioned increase in total margin ($5.6 million) partially offset by higher operating and depreciation expenses. The higher expenses include greater Energy Services operating and depreciation expenses associated with peaking assets and greater Electric Generation operating and depreciation expenses ($0.7 million) including higher maintenance expenses associated with planned outages at the Conemaugh generating station in which we own a 5.97% interest. The increase in Midstream & Marketing’s income before income taxes reflects the greater operating income ($3.3 million) and lower interest expense on borrowings under the Energy Services Credit Agreement.

Interest Expense and Income Taxes. Our consolidated interest expense was $2.1 million lower in the 2013 three-month period principally reflecting slightly lower AmeriGas Propane, UGI Utilities and Energy Services interest expense the result of lower average debt outstanding. Our consolidated effective tax rate (as calculated as a percentage of pretax income (loss) excluding noncontrolling interests not subject to income taxes) for the three months ended June 30, 2013, was comparable to such rate for the prior-year three-month period.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

2013 nine-month period compared to the 2012 nine-month period
Net income (loss) attributable to UGI Corporation by Business Unit:

	Nine Months Ended June 30,					
	2013		2012		Variance - Favorable (Unfavorable)	
(Millions of dollars)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane (a)	$52.8	18.3 %	$26.0	12.1 %	$26.8	103.1 %
International Propane (b)	97.3	33.6 %	72.9	34.0 %	24.4	33.5 %
Gas Utility	96.2	33.3 %	84.4	39.4 %	11.8	14.0 %
Midstream & Marketing	46.6	16.1 %	34.2	16.0 %	12.4	36.3 %
Corporate & Other	(3.7)	(1.3)%	(3.4)	(1.5)%	(0.3)	N.M.
Net income attributable to UGI Corporation	$289.2	100.0 %	$214.1	100.0 %	$75.1	35.1 %

N.M. — Variance is not meaningful.
(a) Net income from AmeriGas Propane in the 2012 nine-month period includes after-tax loss of $2.2 million associated with extinguishments of debt.
(b) Net income from International Propane in the 2012 nine-month period includes the benefit of $4.7 million related to the realization of previously unrecognized foreign tax credits.

AmeriGas Propane:

For the nine months ended June 30,	2013	2012	Increase	
(Millions of dollars)				
Revenues	$2,634.6	$2,411.3	$223.3	9.3 %
Total margin (a)	$1,264.4	$963.5	$300.9	31.2 %
Partnership EBITDA (b)	$550.5	$310.0	$240.5	77.6 %
Operating income (b)	$403.9	$206.7	$197.2	95.4 %
Retail gallons sold (millions)	1,039.8	814.3	225.5	27.7 %
Degree days—% (warmer) than normal (c)	(4.1)%	(18.3)%	—	—

(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 nine months ended June 30, 2013, includes transition expenses of $20.7 million associated with Heritage Propane. Partnership EBITDA for the nine months ended June 30, 2012, includes acquisition and transition expenses of $26.9 million associated with Heritage Propane and a pre-tax loss of $13.3 million associated with extinguishments of debt.

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

Results for the 2013 nine-month period reflect the full-period operations of Heritage Propane acquired in January 2012. Based upon heating degree-day data, temperatures in the Partnership's service territories during the 2013 nine-month period averaged approximately 4.1% warmer than normal but 16.8% colder than the 2012 nine-month period. AmeriGas Propane retail gallons sold were 225.5 million gallons (27.7%) greater than in the prior-year period principally reflecting the full-period impact of the Heritage Propane operations and the colder 2013 nine-month period weather.

Retail propane revenues increased $220.7 million during the 2013 nine-month period reflecting the higher retail volumes sold ($583.4 million) partially offset by a decline in average retail selling prices ($362.7 million) which were the result of lower propane product costs. Wholesale propane revenues declined $34.5 million principally reflecting lower average wholesale propane selling prices ($32.3 million) and lower wholesale volumes sold ($2.2 million). Average daily wholesale propane commodity prices during the 2013 nine-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 28% lower than such prices during the prior-year nine-month period. Total revenues from fee income and other ancillary sales and services in the 2013 nine-month period were $37.0 million higher than in the 2012 nine-month period principally reflecting the full-period effects of Heritage Propane. Total propane cost of sales decreased $88.1 million during the 2013 nine-month period principally reflecting the effects of the lower propane commodity prices on retail propane cost of sales ($403.8 million) and lower wholesale propane cost of sales ($37.2 million) substantially offset by the effects of the greater retail volumes sold ($352.9 million). Cost of sales associated with ancillary sales and services increased $10.5 million principally reflecting the full-period effects of Heritage Propane.

Total margin increased $300.9 million in the 2013 nine-month period principally reflecting higher total propane margin ($274.3 million) and greater total margin from ancillary sales and services ($26.6 million). These increases principally reflect the incremental full-period effects of Heritage Propane, the colder 2013 nine-month period weather and, with respect to total propane margin, slightly higher 2013 nine-month period average unit margins reflecting the lower propane product costs.

Partnership EBITDA in the 2013 nine-month period increased $240.5 million principally reflecting the higher total margin ($300.9 million) and the absence of the $13.3 million loss on extinguishments of debt recorded in the prior-year period partially offset by higher Partnership operating and administrative expenses ($78.2 million) primarily attributable to the full-period effects of Heritage Propane operations. Operating and administrative expenses in the 2013 nine-month period include $20.7 million of transition expenses associated with the integration of Heritage Propane while operating and administrative expenses in the prior-year period include Heritage Propane acquisition and transition-related expenses of $26.9 million. Partnership operating income increased $197.2 million in the 2013 nine-month period principally reflecting the higher total margin ($300.9 million) partially offset by the previously mentioned greater operating and administrative expenses ($78.2 million) and increased depreciation and amortization expense ($32.0 million) reflecting in large part the full-period effects of Heritage Propane.

International Propane:

For the nine months ended June 30,	2013	2012	Increase	
(Millions of dollars)				
Revenues	$1,780.1	$1,605.2	$174.9	10.9 %
Total margin (a)	$558.6	$501.0	$57.6	11.5 %
Operating income	$160.4	$113.1	$47.3	41.8 %
Income before income taxes	$137.7	$89.8	$47.9	53.3 %
Retail gallons sold (b)	474.9	466.2	8.7	1.9 %
Antargaz degree days—% colder (warmer) than normal (c)	5.2 %	(7.2)%	—	—
Flaga degree days—% colder (warmer) than normal (c)	0.4 %	(5.6)%	—	—

(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 and Flaga service territories.

Based upon heating degree day data, temperatures in our European LPG operations were colder than normal and the prior year. Although wholesale commodity prices for propane and butane based upon index prices in northwest Europe for the 2013 nine-month period averaged approximately the same as in the 2012 nine-month period, such LPG prices in northwest Europe generally declined during the 2013 peak heating season while LPG prices generally increased during the prior-year peak heating season. Retail LPG gallons sold were slightly higher than the prior-year period principally reflecting the effects of significantly colder weather across all of our European operations partially offset by the effects of a decline in economic activity mainly on commercial and industrial customers in certain of our European markets.

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 2013 and 2012 nine-month periods, the average un-weighted translation rate was approximately $1.31 and $1.32 per euro, respectively. The difference in rates did not have a material impact on net income attributable to UGI.

International Propane revenues increased $174.9 million principally reflecting the effects on LPG revenues of greater low-margin wholesale sales, the increase in LPG retail volumes sold and greater average retail prices. The increase in revenues also reflects higher revenues from natural gas marketing activities in France. Cost of sales increased to $1,221.5 million in the 2013 nine-month period from $1,104.2 million in the prior-year period principally reflecting the effects of the greater retail and wholesale LPG

volumes sold. The higher International Propane cost of sales also reflects increased cost of sales associated with natural gas marketing activities in France.
Total International Propane margin increased $57.6 million during the 2013 nine-month period principally reflecting higher retail LPG unit margins and volumes at Antargaz and, to a much lesser extent, greater total LPG margin at AvantiGas and Flaga.
International Propane operating income and income before income taxes increased $47.3 million and $47.9 million, respectively, principally reflecting the higher total margin ($57.6 million) partially offset by modestly higher operating and administrative expenses. Operating and administrative expenses in the 2013 nine-month period include higher delivery, selling, and incentive compensation and benefits costs at Antargaz partially offset by slightly lower operating and administrative costs at Flaga and AvantiGas. The prior-year nine-month period operating and administrative expenses include acquisition and transition costs of approximately $5.9 million associated with the LPG businesses acquired from Shell in October 2011. Net income from International Propane operations in the 2013 nine-month period as a percentage of earnings before taxes was lower than the prior-year period as the estimated annual income tax rate in the prior year reflects, in part, the effects of a greater proportion of International Propane tax benefits relative to pre-tax income and the realization of $4.7 million of previously unrecognized foreign tax credits.

Gas Utility:

For the nine months ended June 30,	2013	2012	Increase		
(Millions of dollars)					
Revenues	$743.6	$696.8	$46.8	6.7	%
Total margin (a)	$370.9	$326.2	$44.7	13.7	%
Operating income	$191.6	$168.7	$22.9	13.6	%
Income before income taxes	$163.5	$138.6	$24.9	18.0	%
System throughput—billions of cubic feet (“bcf”) —					
Core market	65.4	54.7	10.7	19.6	%
Total	158.5	146.0	12.5	8.6	%
Degree days—% (warmer) than normal (b)	(1.2)%	(16.6)%	—	—	

(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 2013 nine-month period based upon heating degree days were 1.2% warmer than normal but 14.9% colder than the prior-year period. Total distribution system throughput increased principally reflecting significantly higher throughput to core market customers and, to a lesser extent, greater net volumes associated with lower margin firm and interruptible delivery service customers. Gas Utility system throughput to core-market customers was above last year principally reflecting the effects of the significantly colder weather and, to a much lesser extent, customer growth, principally conversions from oil prompted by sustained lower natural gas prices and high oil prices.

Gas Utility revenues increased $46.8 million during the 2013 nine-month period principally reflecting higher revenues from core market customers ($44.2 million) and higher large firm delivery service revenues ($7.7 million) partially offset by lower off-system sales revenues ($6.1 million). The increase in core market revenues principally reflects the effects of the higher core market volumes on PGC revenues ($52.0 million) and greater core market delivery service revenues partially offset by the effects of lower average PGC rates on retail core-market revenues ($46.7 million). Gas Utility’s cost of gas was $372.7 million in the 2013 nine-month period compared with $370.6 million in the prior-year period principally reflecting the effects on cost of sales of the greater retail core-market volumes ($52.0 million) substantially offset by the effects of lower average PGC rates ($46.7 million) and the lower off-system sales.

Gas Utility total margin increased $44.7 million in the 2013 nine-month period principally reflecting higher core market margin ($34.5 million) and higher large firm delivery service total margin ($8.1 million). The higher core market total margin reflects the effects of the greater core market volumes.

The increase in Gas Utility operating income during the 2013 nine-month period principally reflects the increase in total margin ($44.7 million) partially offset by higher operating and administrative expenses ($17.0 million) including, among other things, higher pension and benefits expenses ($3.0 million), higher uncollectible accounts expenses ($2.8 million) on higher core market volumes, and greater injuries and damages and distribution system expenses ($4.0 million). The greater income before income taxes in the 2013 nine-month period reflects the higher operating income ($22.9 million) and slightly lower interest expense on lower long-term debt outstanding.

Midstream & Marketing:

For the nine months ended June 30,	2013	2012	Increase		
(Millions of dollars)					
Revenues (a)	$809.9	$674.5	$135.4	20.1	%
Total margin (b)	$135.8	$108.9	$26.9	24.7	%
Operating income	$79.7	$59.4	$20.3	34.2	%
Income before income taxes	$77.3	$55.8	$21.5	38.5	%

(a) Amounts are net of intercompany revenues between Midstream & Marketing's Energy Services and Electric Generation segments.
(b) Total margin represents total revenues less total cost of sales.

Midstream & Marketing total revenues increased $135.4 million in the 2013 nine-month period principally reflecting, among other things, higher natural gas revenues ($101.2 million) from higher wholesale volumes sold and higher average selling prices for natural gas, and higher Electric Generation total revenues ($20.5 million) principally the result of higher electricity volumes and prices.

Midstream & Marketing total margin in the 2013 nine-month period was $26.9 million higher than the prior-year period reflecting higher natural gas marketing total margin ($12.9 million), higher Electric Generation total margin ($10.2 million) and greater peaking and capacity management total margin ($8.9 million) due to the colder weather and greater natural gas price volatility. Total margin from natural gas marketing activities in the 2013 nine-month period principally reflects the benefits of higher average unit margins. Natural gas marketing average unit margins in the 2013 nine-month period benefited from higher-margin incremental sales resulting from the colder weather while average unit margins in the prior-year period were negatively impacted by significantly warmer than normal weather. The greater total margin from Electric Generation principally reflects the impact of higher electricity production from our Hunlock Creek natural gas-fired electricity generating station and greater volumes sold from the Conemaugh generating station. As previously mentioned, in the prior-year period the Hunlock Creek 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. Unit margins from Electric Generation were higher in the 2013 nine-month period reflecting higher electricity spot market prices.

Midstream & Marketing operating income in the 2013 nine-month period was $20.3 million higher than the prior-year period reflecting the previously mentioned increase in total margin ($26.9 million) partially offset by higher operating and depreciation expenses. The higher operating and depreciation expenses include greater Energy Services depreciation and operating expenses ($5.5 million) due in large part to expenses associated with peaking LNG liquefaction and storage facilities. The increase in Midstream & Marketing income before income taxes reflects the greater operating income ($20.3 million) and lower interest expense on Energy Services' Credit Agreement and Receivables Facility borrowings.

Interest Expense and Income Taxes. Our consolidated interest expense was $17.0 million higher in the 2013 nine-month period primarily reflecting higher AmeriGas Propane interest expense ($20.8 million), principally full-period interest on debt issued to fund the cash portion of the January 12, 2012, Heritage Acquisition. Income taxes as a percentage of pretax earnings was lower in the 2013 nine-month period reflecting the effects of a higher percentage of income associated with noncontrolling interests, principally AmeriGas Partners, not subject to tax and the realization of previously unrecognized state deferred tax benefits while taxes in the prior-year nine-month period were reduced by $4.7 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. We believe that each of our business units has sufficient liquidity in the forms of cash and cash equivalents on hand, cash expected to be generated from operations, and credit facilities and receivables purchase facility borrowings, and the ability to obtain long-term financing to meet anticipated contractual and projected cash commitments.

Issuances of debt and equity securities in the capital markets and additional credit facilities may not, however, be available to us on acceptable terms.
Our cash and cash equivalents totaled $401.8 million at June 30, 2013, compared with $319.9 million at September 30, 2012. Excluding cash and cash equivalents that reside at UGI's operating subsidiaries, at June 30, 2013 and September 30, 2012, UGI had $100.0 million and $107.9 million, respectively, of cash and cash equivalents.
The Company's debt outstanding at June 30, 2013, totaled $3,629.7 million (including current maturities of long-term debt of $195.6 million and bank loan borrowings of $135.9 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 June 30, 2013, consists of (1) $2,383.2 million of Partnership debt; (2) $588.0 million (€452.1 million) of International Propane debt; (3) $600.0 million of UGI Utilities' debt; (4) $46.6 million of Midstream & Marketing debt; and (5) $11.9 million of other debt.
AmeriGas Partners' total debt at June 30, 2013, includes $2,250.8 million of AmeriGas Partners' Senior Notes, $80.0 million of AmeriGas OLP bank loan borrowings and $52.4 million of other long-term debt.
International Propane's total debt at June 30, 2013, includes $494.4 million (€380 million) outstanding under Antargaz' Senior Facilities term loan and a combined $78.7 million (€60.5 million) outstanding under Flaga's three term loans. Total International Propane debt outstanding at June 30, 2013, also includes combined borrowings of $10.4 million outstanding under all of Flaga's working capital facilities and $4.5 million (€3.5 million) of other long-term debt.
UGI Utilities' total debt at June 30, 2013, includes $383 million of Senior Notes and $217 million of Medium-Term Notes. At June 30, 2013, UGI Utilities had no bank loan borrowings.

AmeriGas Partners. AmeriGas OLP has a $525 million unsecured credit agreement ("AmeriGas Credit Agreement"). At June 30, 2013, there were $80.0 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 June 30, 2013. Average daily and peak bank loan borrowings outstanding under the AmeriGas Credit Agreement during the 2013 nine-month period were $106.6 million and $200.5 million, respectively. The average daily and peak bank loan borrowings outstanding during the 2012 nine-month period were $111.5 million and $239.5 million, respectively. At June 30, 2013, the Partnership's available borrowing capacity under the AmeriGas Credit Agreement was $390.9 million.
International Propane. Antargaz has a Senior Facilities Agreement with a consortium of banks ("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 June 30, 2013, the effective interest rate on Antargaz' term loan was 4.66%. Antargaz had no amounts outstanding under its revolving credit facility at June 30, 2013.

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. Flaga expects to extend the Euro Facility prior to its expiration. At June 30, 2013, there were €3.4 million ($4.4 million) of borrowings outstanding under the Flaga Credit Agreements.
Issued and outstanding guarantees, which reduce available borrowings under the Flaga Credit Agreements, totaled €18.8 million ($24.4 million) at June 30, 2013. The average daily and peak bank loan borrowings outstanding under the

Flaga Credit Agreements during the 2013 nine-month period were €5.1 million and €11.9 million, respectively. The average daily and peak bank loan borrowings outstanding under the Flaga Credit Agreements during the 2012 nine-month period were €13.4 million and €14.5 million, respectively.

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 June 30, 2013, there were no amounts outstanding under the UGI Utilities Credit Agreement. During the 2013 and 2012 nine-month periods, average daily bank loan borrowings were $27.3 million and $21.3 million, respectively, and peak bank loan borrowings totaled $79.0 million and $70.6 million, respectively. Peak bank loan borrowings typically occur during the heating season months of December and January.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

UGI Utilities has an aggregate $133 million of Senior Notes and Medium-Term Notes maturing late in Fiscal 2013 which UGI Utilities intends to refinance on a long-term basis.
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 June 30, 2013. During the 2013 and 2012 nine-month periods, peak borrowings under the Energy Services Credit Agreement were $85 million.
Energy Services also has a $100 million receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper. In April 2013, Energy Services amended its Receivables Facility to extend its expiration until November 2013 and reduce the facility to $100 million from $200 million previously. The Receivables Facility may terminate prior to its expiration 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 and amend the receivables purchase limits to better align such limits with Energy Services seasonal borrowing needs.
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 nine months ended June 30, 2013 and 2012, Energy Services transferred trade receivables totaling $766.1 million and $674.4 million, respectively, to ESFC. During the nine months ended June 30, 2013 and 2012, ESFC sold an aggregate $224.0 million and $266.5 million, respectively, of undivided interests in its trade receivables to the commercial paper conduit. At June 30, 2013, the balance of ESFC receivables was $58.2 million and there was $9.5 million sold to the commercial paper conduit. At June 30, 2012, the outstanding balance of ESFC receivables was $41.0 million and there was $10.0 million sold to the commercial paper conduit. During the nine months ended June 30, 2013 and 2012, peak amounts sold under the Receivables Facility were $46.5 million and $51.5 million, respectively, and average daily amounts sold were $8.6 million and $21.9 million, respectively.
Dividends and Distributions. On July 30, 2013, UGI's Board of Directors approved a quarterly dividend of $0.2825 per common share payable October 1, 2013, to shareholders of record September 16, 2013. On April 30, 2013, UGI's Board of Directors approved an increase in the quarterly dividend rate on UGI Common Stock to $0.2825 per Common Share or $1.13 on an annual basis. The dividend reflects an approximate 4.6% increase from the previous quarterly rate of $0.27. The new quarterly dividend rate was effective with the dividend payable on July 1, 2013, to shareholders of record on June 14, 2013.
On July 29, 2013, the General Partner's Board of Directors approved a quarterly distribution of $0.84 per Common Unit payable August 19, 2013 to unitholders of record August 9, 2013. On April 29, 2013, the General Partner's Board of Directors approved an increase in the quarterly dividend rate on AmeriGas Partners Common Units to $0.84 per Common Unit equal to an annual rate of $3.36 per Common Unit. The distribution reflects a 5% increase from the previous quarterly rate of $0.80. The new quarterly rate was effective with the distribution payable on May 17, 2013, to unitholders of record on May 10, 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 by operating activities was $686.4 million in the 2013 nine-month period compared to $566.2 million in the 2012 nine-month period. Cash flow from operating activities before changes in operating working capital was $801.2 million in the 2013 nine-month period compared to $523.7 million in the prior-year nine-month period. The increase in cash flow from operating activities before changes in operating working capital largely reflects the effects of the higher operating results in the 2013 nine-month period. Cash required to fund changes in operating working capital totaled $114.8 million in the 2013 nine-month period compared to cash provided by changes in operating working capital of $42.5 million in the prior-year nine-month period. The cash required to fund changes in operating working capital in the 2013 nine-month period reflects, among other things, greater cash needed to fund operating working capital associated with the increased nine-month period sales while cash provided by changes in operating working capital in the prior-year period benefited from the timing of the acquisition of Heritage Propane on cash receipts from Heritage Propane customers. This greater use of cash in the current-year period was

Table of Contents

partially offset by, among other things, the timing and amount of cash payments associated with accounts payable including the impact of lower LPG product costs.

Investing Activities. Cash flow used by investing activities was $316.7 million in the 2013 nine-month period compared with $1,800.0 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 2013 nine-month period largely reflects Midstream and Marketing's acquisition of a non-operating working interest in natural gas acreage in the Marcellus Shale region of Pennsylvania. Cash paid for acquisitions in the prior-year nine-month period principally reflects the January 2012 Heritage Acquisition and the October 2011 acquisition of certain of Shell's European LPG businesses.

Financing Activities. Cash flow used by financing activities was $286.0 million in the 2013 nine-month period compared with cash flow provided by financing activities of $1,434.8 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 2013 nine-month period increased over the prior-year period reflecting the greater number of Common Units outstanding subsequent to the Heritage Acquisition and higher quarterly per-unit distribution rates. In order to finance the cash portion of the Heritage Acquisition, on January 12, 2012, AmeriGas Partners issued $550 million principal amount of 6.75% Notes due 2020 and $1.0 billion principal amount of 7.00% Notes due 2022. During March 2012, AmeriGas Partners sold 7 million Common Units in an underwritten public offering and used a portion of the net proceeds to repay $200 million of outstanding 6.50% Senior Notes due May 2021, to reduce bank loan borrowings and for general corporate purposes.

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, 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. On February 19, 2013, the PUC entered a final order (the "Final Order") in which PUC Commissioners adopted the Joint Settlement, with certain modifications. The Final Order requires 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. The Final Order makes no findings that UGI Utilities has violated any regulation or operating procedure. The Company does not believe that the cost of complying with the requirements of the Final Order will have a material impact on UGI Utilities' consolidated financial position, results of operations or cash flows.

Table of Contents

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 June 30, 2013, the fair values of Gas Utility’s natural gas futures and option contracts were net losses of $1.4 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of financial transmission rights (“FTRs”) and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2013, the fair values of Electric Utility’s electricity supply contracts were net losses of $6.1 million. At June 30, 2013, 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 June 30, 2013, 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, ICE and over-the-counter natural gas and electricity futures and natural gas basis swap contracts or enters into fixed-price supply arrangements. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to 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 June 30, 2013 (excluding those Gas Utility and Electric Utility commodity derivative instruments which are refundable to or recoverable from customers) was a loss of $14.8 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 $35.2 million at June 30, 2013.

Interest Rate Risk

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

Our variable-rate debt at June 30, 2013, 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 June 30, 2013, combined borrowings outstanding under these variable-rate debt agreements, excluding Antargaz' and Flaga's effectively fixed-rate debt, totaled $135.9 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 June 30, 2013 (including pay-fixed, receive-variable interest rate swaps) was a loss of $38.8 million. A hypothetical 10% adverse change in the three-month euribor would increase such loss by approximately $10.3 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 June 30, 2013, 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 June 30, 2013, by approximately $89.8 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.

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.

The fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at June 30, 2013, was a loss of $0.8 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 $19.7 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 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 June 30, 2013 and 2012, restricted cash in brokerage accounts totaled $6.0 million and $7.6 million, respectively.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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. Effective June 20, 2013, we entered into a settlement agreement with BP and the lawsuit has been dismissed.

ITEM 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.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

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	UGI Corporation Senior Executive Employee Severance Plan, as amended and restated as of November 16, 2012.			
10.2	UGI Corporation Executive Employee Severance Plan, as amended and restated as of November 16, 2012.			
10.3	AmeriGas Propane, Inc. Senior Executive Employee Severance Plan, as amended and restated as of November 15, 2012.	AmeriGas Partners, L.P.	Form 10-Q (6/30/2013)	10.1
10.4	AmeriGas Propane, Inc. Executive Employee Severance Plan, as amended and restated as of November 15, 2012.	AmeriGas Partners, L.P.	Form 10-Q (6/30/2013)	10.2
10.5	UGI Utilities, Inc. Senior Executive Employee Severance Plan, as amended and restated as of November 16, 2012.	UGI Utilities, Inc.	Form 10-Q (6/30/2013)	10.1
10.6	Letter Agreement, dated as of June 10, 2013, amending SST Service Agreement No. 79133 dated March 29, 2012 between Columbia Gas Transmission, LLC and UGI Utilities, Inc.	UGI Utilities, Inc.	Form 10-Q (6/30/2013)	10.3
10.7	FTS Service Agreement No. 46284 dated July 23, 2013 between Columbia Gas Transmission, LLC and UGI Utilities, Inc.	UGI Utilities, Inc.	Form 8-K (7/23/2013)	10.1
31.1	Certification by the Chief Executive Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2013, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.2	Certification by the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2013, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2013, 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

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

SIGNATURES

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

UGI Corporation
(Registrant)

Date: August 2, 2013	By: /s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: August 2, 2013	By: /s/ Davinder S. Athwal Davinder S. Athwal Vice President - Accounting and Financial Control and Chief Risk Officer

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

EXHIBIT INDEX

10.1	UGI Corporation Senior Executive Employee Severance Plan, as amended and restated as of November 16, 2012.
10.2	UGI Corporation Executive Employee Severance Plan, as amended and restated as of November 16, 2012.
31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2013, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2013, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2013, 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