ARRAY BIOPHARMA INC
Form 10-Q
February 06, 2013

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

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended December 31, 2012

or

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number: 001-16633

Array BioPharma Inc.	
(Exact Name of Registrant as Specified in Its Charter)	
Delaware	84-1460811
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
3200 Walnut Street, Boulder, CO	80301
(Address of Principal Executive Offices)	(Zip Code)

(303) 381-6600
(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 x 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x 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.

Large Accelerated Filer ¨	Accelerated Filer x
Non-Accelerated Filer ¨ (do not check if smaller reporting company)	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 x

As of January 31, 2013, the registrant had 116,661,219 shares of common stock outstanding.

ARRAY BIOPHARMA INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED December 31, 2012
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PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED FINANCIAL STATEMENTS
ARRAY BIOPHARMA INC.
Condensed Balance Sheets
(Amounts in Thousands, Except Share and Per Share Amounts)
(Unaudited)

	December 31, 2012	June 30, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$59,565	$55,799
Marketable securities	49,616	33,378
Prepaid expenses and other current assets	5,098	3,930
Total current assets	114,279	93,107
Long-term assets		
Marketable securities	664	473
Property and equipment, net	11,245	12,059
Other long-term assets	2,185	2,434
Total long-term assets	14,094	14,966
Total assets	$128,373	$108,073
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Accounts payable	$4,726	$6,466
Accrued outsourcing costs	4,509	5,394
Accrued compensation and benefits	5,098	7,530
Other accrued expenses	1,896	1,390
Co-development liability	3,970	9,178
Deferred rent	3,567	3,489
Deferred revenue	26,534	42,339
Current portion of long-term debt	—	150
Total current liabilities	50,300	75,936
Long-term liabilities		
Deferred rent	9,661	11,480
Deferred revenue	4,569	13,228
Long-term debt, net	94,417	92,106
Derivative liabilities	479	656
Other long-term liabilities	664	473
Total long-term liabilities	109,790	117,943
Total liabilities	160,090	193,879
Commitments and contingencies		
Stockholders' deficit		
Preferred stock, $0.001 par value; 10,000,000 shares authorized, 10,135 shares designated as Series B convertible preferred stock; 0 and 2,721 shares issued and outstanding as of December 31, 2012 and June 30, 2012, respectively	—	8,054

Common stock, $0.001 par value; 220,000,000 and 120,000,000 shares authorized; 116,660,469 and 92,063,645 shares issued and outstanding, as of December 31, 2012 and June 30, 2012, respectively	117	92
Additional paid-in capital	522,214	437,401
Warrants	39,385	39,385
Accumulated other comprehensive income (loss)	2	(1)
Accumulated deficit	(593,435)	(570,737)
Total stockholders' deficit	(31,717)	(85,806)
Total liabilities and stockholders' deficit	$128,373	$108,073

The accompanying notes are an integral part of these condensed financial statements.

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ARRAY BIOPHARMA INC.
Condensed Statements of Operations and Comprehensive Loss
(Amounts in Thousands, Except Per Share Data)
(Unaudited)

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
Revenue				
License and milestone revenue	$14,016	$19,195	$26,492	$37,657
Collaboration revenue	4,361	4,033	7,718	7,701
Total revenue	18,377	23,228	34,210	45,358
Operating expenses				
Cost of revenue	7,909	6,266	14,448	12,711
Research and development for proprietary programs	13,941	13,150	27,475	25,748
General and administrative	4,610	3,782	9,390	7,502
Total operating expenses	26,460	23,198	51,313	45,961
Income (loss) from operations	(8,083)	30	(17,103)	(603)
Other income (expense)				
Interest income	12	3	24	9
Interest expense	(2,860)	(3,836)	(5,619)	(6,792)
Total other expenses, net	(2,848)	(3,833)	(5,595)	(6,783)
Net loss	$(10,931)	$(3,803)	$(22,698)	$(7,386)
Change in unrealized gains and losses on marketable securities	—	1	3	(3)
Comprehensive loss	$(10,931)	$(3,802)	$(22,695)	$(7,389)
Weighted average shares outstanding - basic and diluted	105,403	60,004	99,005	58,515
Net loss per share - basic and diluted	$(0.10)	$(0.06)	$(0.23)	$(0.13)

The accompanying notes are an integral part of these condensed financial statements.

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ARRAY BIOPHARMA INC.
Condensed Statement of Stockholders' Deficit
(Amounts in Thousands)
(Unaudited)

	Preferred stock Shares	Preferred stock Amounts	Common stock Shares	Common stock Amounts	Additional paid-in capital	Warrants	Accumulated other comprehensive income (loss)	Accumulated deficit	Total
Balance as of July 1, 2012	3	$ 8,054	92,064	$ 92	$ 437,401	$ 39,385	$ (1)	$ (570,737)	$ (85,806)
Issuance of common stock under stock option and employee stock purchase plans	—	—	682	1	1,453	—	—	—	1,454
Share-based compensation expense	—	—	—	—	1,562	—	—	—	1,562
Issuance of common stock for cash, net of offering costs	—	—	20,700	21	70,890	—	—	—	70,911
Conversion of preferred stock to common	(3)	(8,054)	2,721	3	8,051	—	—	—	—
Payment of employee bonus with stock	—	—	493		2,857	—	—	—	2,857
Change in unrealized gain on marketable securities	—	—	—	—	—	—	3	—	3
Net loss	—	—	—	—	—	—	—	(22,698)	(22,698)
Balance as of December 31, 2012	—	$ —	116,660	$ 117	$ 522,214	$ 39,385	$ 2	$ (593,435)	$ (31,717)

The accompanying notes are an integral part of these condensed financial statements.

ARRAY BIOPHARMA INC.
Condensed Statements of Cash Flows
(Amounts in Thousands)
(Unaudited)

	Six Months Ended December 31,	
	2012	2011
Cash flows from operating activities		
Net loss	$(22,698)	$(7,386)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation and amortization expense	2,278	2,630
Non-cash interest expense	2,158	2,329
Loss on prepayment of long-term debt	—	942
Share-based compensation expense	1,562	1,156
Payment of employee bonus with stock	2,857	1,969
Changes in operating assets and liabilities:		
Prepaid expenses and other assets	(1,092)	1,856
Accounts payable	(1,235)	488
Accrued outsourcing costs	(885)	(877)
Accrued compensation and benefits	(2,432)	(1,672)
Co-development liability	(5,208)	2,146
Deferred rent	(1,741)	(1,663)
Deferred revenue	(24,464)	(7,946)
Other liabilities and accrued expenses	137	(123)
Net cash used in operating activities	(50,763)	(6,151)
Cash flows from investing activities		
Purchases of property and equipment	(1,464)	(926)
Purchases of marketable securities	(62,022)	(4,940)
Proceeds from sales and maturities of marketable securities	45,650	20,552
Net cash provided by (used in) investing activities	(17,836)	14,686
Cash flows from financing activities		
Proceeds from exercise of stock options and shares issued under stock option and employee stock purchase plans	1,454	879
Proceeds from the issuance of common stock for cash	75,555	7,345
Payment of offering costs	(4,644)	(295)
Payment of principal of long-term debt	—	(4,200)
Net cash provided by financing activities	72,365	3,729
Net increase in cash and cash equivalents	3,766	12,264
Cash and cash equivalents as of beginning of period	55,799	48,099
Cash and cash equivalents as of end of period	$59,565	$60,363
Supplemental disclosure of cash flow information		
Cash paid for interest	$3,463	$3,546

The accompanying notes are an integral part of these condensed financial statements.

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ARRAY BIOPHARMA INC.
Notes to the unaudited condensed financial statements

NOTE 1 – OVERVIEW AND BASIS OF PRESENTATION

Organization

Array BioPharma Inc. is a biopharmaceutical company focused on the discovery, development and commercialization of targeted small molecule drugs to treat patients afflicted with cancer. During 2013, Array expects to make substantial progress in generating data to inform registration study decisions for our wholly-owned hematology programs, ARRY-520 and ARRY-614. Array-invented MEK162 will be tested in a Phase 3 trial in NRAS melanoma which is scheduled to start in April 2013, as well as BRAF mutant melanoma later in 2013 (with Novartis). Also, AstraZeneca recently announced a potential start of a Phase 3 trial with Array-invented selumetinib in non-small cell lung cancer during the second half of 2013.

Basis of Presentation

We follow the accounting guidance outlined in the Financial Accounting Standards Board Codification. The accompanying unaudited Condensed Financial Statements have been prepared without audit and do not include all of the disclosures required by the Financial Accounting Standards Board Codification, which have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission, whom we refer to as the SEC, relating to requirements for interim reporting. The June 30, 2012 Condensed Balance Sheet data were derived from audited financial statements but do not include all disclosures required by generally accepted accounting principles in the United States, commonly referred to as GAAP. The unaudited Condensed Financial Statements reflect all adjustments (consisting only of normal recurring adjustments) that, in the opinion of management, are necessary to present fairly our financial position as of December 31, 2012 and June 30, 2012, and our results of operations for the three and six months ended December 31, 2012 and 2011, and our cash flows for the six months ended December 31, 2012 and 2011. Operating results for the three and six months ended December 31, 2012 are not necessarily indicative of the results that may be expected for the year ending June 30, 2013.

These unaudited Condensed Financial Statements should be read in conjunction with our audited Financial Statements and the notes thereto included in our Annual Report on Form 10-K for the year ended June 30, 2012 filed with the SEC on August 16, 2012.

For the six months ended December 31, 2011, we reclassified the activity in our co-development liability under the Novartis agreement, as further described under Note 4 - Deferred Revenue - Novartis, from other liabilities and accrued expenses to co-development liability in our Condensed Statements of Cash Flows to conform to the current period presentation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Although management bases these estimates on historical data and other assumptions believed to be reasonable under the circumstances, actual results could differ significantly from these estimates under different assumptions or conditions.

We believe the accounting estimates having the most significant impact on the financial statements relate to: (i) estimating the stand-alone value of deliverables for purposes of determining revenue recognized under partnerships and collaborations involving multiple elements; (ii) estimating the periods over which up-front and milestone payments from partnership and collaboration agreements are recognized; (iii) estimating accrued outsourcing costs for clinical trials and preclinical testing; and (iv) estimating the fair value of our long-term debt and the associated embedded derivatives.

Liquidity

We have incurred operating losses and an accumulated deficit as a result of ongoing research and development spending since inception. As of December 31, 2012, we had an accumulated deficit of $593.4 million. We had net losses of $10.9 million and $22.7 million for the three and six months ended December 31, 2012, respectively, and $23.6 million, $56.3 million and $77.6 million for the fiscal years ended June 30, 2012, 2011 and 2010, respectively.

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During the first six months of fiscal 2013, our net cash used in operations was $50.8 million. We have historically funded our operations from up-front fees and license and milestone payments received under our partnerships, from the issuance and sale of equity securities and through debt provided by our credit facilities. For example, we received net proceeds of approximately $127.0 million during calendar year 2012 from underwritten public offerings of our common stock, after underwriting discounts, commissions and related offering expenses, and have received $175.8 million from up-front, license and milestone payments under our partnerships since December 2009, including the following payments:

- In December 2009, we received a $60 million up-front payment from Amgen Inc. under a Collaboration and License Agreement.

- In May and June 2010, we received a total of $45 million in up-front and milestone payments under a License Agreement with Novartis Pharmaceutical International Ltd.

- In December 2010, we received a $10 million milestone payment under a License Agreement with Celgene Corporation.

- In May 2011, we received a $10 million milestone payment under a License Agreement with Novartis Pharmaceutical International Ltd.

- In September 2011, we received a $28 million up-front payment under a License Agreement with Genentech, Inc.

- In June 2012, we received an $8.5 million milestone payment from Amgen following achievement of a pre-defined patient enrollment milestone in a Phase 2 trial.

Until we can generate sufficient levels of cash from operations, which we do not expect to achieve in the foreseeable future, we will continue to utilize existing cash, cash equivalents and marketable securities, and will continue to depend on funds provided from the sources mentioned above, which may not be available or forthcoming.

During the second quarter of fiscal 2013, we began paying our percentage share of the combined development costs incurred since inception under the MEK162 program licensed to Novartis, as discussed in Note 4 – Deferred Revenue – Novartis International Pharmaceutical Ltd., resulting in a $9.2 million payment to Novartis during the quarter. We have reported a $4.0 million payable in the accompanying Condensed Balance Sheets as co-development liability for this obligation as of December 31, 2012. We anticipate paying Novartis a comparable payment during the first half of fiscal 2014.

Management believes that the cash, cash equivalents and marketable securities as of December 31, 2012, will enable us to continue to fund operations in the normal course of business, including receipt of potential up-front and milestone payments, for at least the next 12 months. Because sufficient funds may not be available to us when needed from existing partnerships, we expect that we will be required to continue to fund our operations in part through the sale of debt or equity securities and through licensing select programs that include up-front and/or milestone payments.

Our ability to successfully raise sufficient funds through the sale of debt or equity securities when needed is subject to many risks and uncertainties and, even if we are successful, future equity issuances would result in dilution to our existing stockholders. We also may not successfully consummate new partnerships that provide for additional up-front fees or milestone payments, or we may not earn milestone payments under such partnerships when anticipated or at all. Our ability to realize milestone or royalty payments under existing partnership agreements and to enter into new partnering arrangements that generate additional revenue through up-front fees and milestone or royalty payments is subject to a number of risks, many of which are beyond our control and include the following:

- The drug development process is risky and highly uncertain and we may not be successful in generating proof-of-concept data to create partnering opportunities and, even if we are successful, we or our partners may not be successful in commercializing drug candidates we create;

- We may fail to select the best drug from our wholly-owned pipeline to advance and invest in registration, or Phase 3 studies;

- Our partners have substantial control and discretion over the timing and continued development and marketing of drug candidates we create and, therefore, we may not receive milestone, royalty or other payments when anticipated or at all;

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- The drug candidates we or our partners develop may not obtain regulatory approval;
- If regulatory approval is received, drugs we develop will remain subject to regulation or may not gain market acceptance, which could delay or prevent us from generating milestone, royalty revenue or product revenue from the commercialization of these drugs; and
- We cannot control or predict the spending priorities and willingness of pharmaceutical companies to in-license drugs for further development and commercialization.

Our assessment of our future need for funding and our ability to continue to fund our operations is a forward-looking statement that is based on assumptions that may prove to be wrong and that involve substantial risks and uncertainties. Our actual future capital requirements could vary as a result of a number of factors, including:

- Our ability to enter into agreements to out-license, co-develop or commercialize our proprietary drug candidates and the timing of payments under those agreements throughout each candidate's development stage;
- The number and scope of our research and development programs;
- The progress and success of our preclinical and clinical development activities;
- The progress and success of the development efforts of our partners;
- Our ability to maintain current collaboration and partnership agreements;
- The costs involved in enforcing patent claims and other intellectual property rights;
- The costs and timing of regulatory approvals; and/or
- The expenses associated with unforeseen litigation, regulatory changes, competition and technological developments, general economic and market conditions and the extent to which we acquire or invest in other businesses, products and technologies.

If we are unable to obtain additional funding from these or other sources when needed, or to the extent needed, it may be necessary to significantly reduce the current rate of spending through reductions in staff and delaying, scaling back, or stopping certain research and development programs, including more costly Phase 2 and Phase 3 clinical trials on our wholly-owned or co-development programs as these programs progress into later stage development. Insufficient liquidity may also require us to relinquish greater rights to product candidates at an earlier stage of development or on less favorable terms to us and our stockholders than we would otherwise choose in order to obtain up-front license fees needed to fund operations. These events could prevent us from successfully executing our operating plan and in the future could raise substantial doubt about our ability to continue as a going concern. Further, as discussed in Note 5 – Long-term Debt, the entire outstanding debt balance of $14.7 million with Comerica Bank (Comerica) and $92.6 million with Deerfield Private Design Fund, L.P. and certain of its affiliates (collectively referred to as Deerfield) becomes due and payable if our total cash, cash equivalents and marketable securities falls below $22 million and $20 million, respectively, at the end of a fiscal quarter. Based on our current forecasts and expectations, which are subject to many factors outside of our control, we do not anticipate that our cash and cash equivalents and marketable securities will fall below this level prior to maturity of such debt.

Revenue Recognition

We recognize revenue based on four criteria, each of which must be met in order to recognize revenue for the performance of services or the shipment of products. Revenue is recognized when (a) persuasive evidence of an arrangement exists, (b) products are delivered or as services are rendered, (c) the sales price is fixed or determinable and (d) collectability is reasonably assured.

We follow ASC 605-25 “Revenue Recognition – Multiple-Element Arrangements” to determine the recognition of revenue under partnership and collaboration agreements that include multiple elements, including research and development services, achievement of development and commercialization milestones and drug product manufacturing. This standard provides guidance on the accounting for arrangements involving the delivery of multiple elements when the delivery of separate units of accounting occurs in different reporting periods. This standard addresses the determination of the units of accounting for multiple-element arrangements and how the arrangement’s consideration should be allocated to

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each unit of accounting. We adopted this accounting standard on a prospective basis for all multiple-element arrangements entered into on or after July 1, 2010, and for any multiple-element arrangements that were entered into prior to July 1, 2010, but materially modified on or after July 1, 2010. The adoption of this standard may result in revenue recognition patterns for future agreements that are materially different from the recognition of revenue under partnership and collaboration arrangements entered into prior to this date.

We evaluate the deliverables to determine if they meet the separation criteria under the standard and have stand-alone value and we allocate revenue to the elements based on their relative selling prices. We treat deliverables in an arrangement that do not meet the separation criteria in this standard as a single unit of accounting, generally applying applicable revenue recognition guidance for the final deliverable to the combined unit of accounting.

We recognize revenue from non-refundable up-front payments and license fees on a straight-line basis over the term of performance under the agreement. When the performance period is not specifically identifiable from the agreement, we estimate the performance period based upon provisions contained within the agreement, such as the duration of the research or development term, the existence, or likelihood of achievement of development commitments and any other significant commitments. For agreements entered into prior to July 1, 2010, the performance period is generally the estimated research or development term. For agreements entered into on or after this date, the performance period is measured as the time between the execution date and the completion of the inseparable technology transfer, which is typically a shorter period, generally up to six months.

We defer the up-front payments and record them as deferred revenue upon receipt, pending recognition. The deferred portions of payments are classified as a short-term or long-term liability in the accompanying Condensed Balance Sheets, depending on the period during which revenue is expected to be recognized.

Most of our agreements provide for milestone payments. In certain cases, we recognize all or a portion of each milestone payment as revenue when the specific milestone is achieved based on the applicable percentage earned of the estimated research or development effort, or other performance obligations that have elapsed, to the total estimated research and/or development effort. In other cases, when the milestone payment is attributed to our future development obligations, we recognize the revenue on a straight-line basis over the estimated remaining development effort. We record milestone payments as deferred revenue upon receipt until recognized.

We periodically review the expected performance periods under each of our agreements that provide for non-refundable up-front payments, license fees and milestone payments. We adjust the amortization periods when appropriate to reflect changes in assumptions relating to the duration of expected performance periods. We could accelerate revenue recognition for non-refundable up-front payments, license fees and milestone payments in the event of early termination of programs. Alternatively, we could decelerate such revenue recognition if programs are extended. While changes to such estimates have no impact on our reported cash flows, our reported revenue may be significantly influenced by our estimates of the period over which our obligations are expected to be performed and, therefore, over which revenue is recognized.

Cost of Revenue and Research and Development Expenses for Proprietary Programs

Where our collaboration agreements provide for us to conduct research and development and for which our partner has an option to obtain the right to conduct further development and to commercialize a product, we attribute a portion of our research and development costs to cost of revenue based on the percentage of total programs under the agreement that we conclude is likely to continue to be funded by the partner. These costs may not be incurred equally across all programs. In addition, we continually evaluate the progress of development activities under these agreements and if events or circumstances change in future periods that we reasonably believe would make it unlikely that a collaborator would continue to fund the same percentage of programs, we will adjust the allocation accordingly.

See Note 4 – Deferred Revenue, for further information about our partnerships.

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Recent Accounting Pronouncements

In June 2011, the FASB issued FASB ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income in U.S. GAAP and IFRS. This ASU provides companies the option to present the components of net income and other comprehensive income either as one continuous statement of comprehensive income or as two separate but consecutive statements. It eliminates the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity. The provisions of this new guidance are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We adopted this disclosure standard in the first quarter of fiscal 2013 and it did not have a material impact on our results of operations.

Other recent accounting pronouncements issued by the FASB (including its Emerging Issues Task Force) and the SEC did not or are not believed by management to have a material impact on our present or future financial statements.

NOTE 2 – SEGMENTS, GEOGRAPHIC INFORMATION AND SIGNIFICANT PARTNERSHIPS

Segments

All operations of Array are considered to be in one operating segment and, accordingly, no segment disclosures have been presented. The physical location of all of our equipment, leasehold improvements and other fixed assets is within the United States (U.S.). All of our partnership and collaboration agreements are denominated in U.S. dollars.

Significant Partnerships

The following partnerships contributed greater than 10% of our total revenue during the periods set forth below. The revenue from these partners as a percentage of total revenue was as follows:

	Three Months Ended December 31,				Six Months Ended December 31,			
	2012		2011		2012		2011	
Amgen Inc.	30.0	%	26.0	%	32.5	%	26.5	%
Novartis International Pharmaceutical, Ltd.	18.7	%	14.8	%	20.3	%	15.2	%
Celgene Corporation	21.6	%	4.1	%	18.4	%	6.1	%
Genentech Inc.	10.5	%	53.7	%	13.2	%	51.1	%
	80.8	%	98.6	%	84.4	%	98.9	%

The loss of one or more of our significant partners could have a material adverse effect on our business, operating results or financial condition. We do not require collateral from our partners, though most pay in advance. Although we are impacted by economic conditions in the biotechnology and pharmaceutical sectors, management does not believe significant credit risk exists as of December 31, 2012.

Geographic Information

The following table details revenue from partnerships by geographic area based on the country in which partners are located (dollars in thousands):

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011

North America	$14,909	$19,517	$27,127	$38,048
Europe	3,465	3,472	7,080	7,068
Asia Pacific	3	239	3	242
	$18,377	$23,228	$34,210	$45,358

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NOTE 3 – MARKETABLE SECURITIES

Marketable securities consisted of the following as of December 31, 2012 (dollars in thousands):

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Short-term available-for-sale securities:				
U.S. Government agency securities	$49,392	$2	$—	$49,394
Mutual fund securities	222	—	—	222
Sub-total	49,614	2	—	49,616
Long-term available-for-sale securities:				
Mutual fund securities	664	—	—	664
Sub-total	664	—	—	664
Total	$50,278	$2	$—	$50,280

Marketable securities consisted of the following as of June 30, 2012 (dollars in thousands):

	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Short-term available-for-sale securities:				
U.S. Government agency securities	$33,129	$—	$(1)	$33,128
Mutual fund securities	250	—	—	250
Sub-total	33,379	—	(1)	33,378
Long-term available-for-sale securities:				
Mutual fund securities	473	—	—	473
Sub-total	473	—	—	473
Total	$33,852	$—	$(1)	$33,851

The majority of the mutual fund securities shown in the above tables are securities held under the Array BioPharma Inc. Deferred Compensation Plan.

The estimated fair value of our marketable securities was classified into the fair value measurement categories as follows (dollars in thousands):

	December 31, 2012	June 30, 2012
Quoted prices in active markets for identical assets (Level 1)	$50,280	$33,851
Observable inputs other than quoted prices in active markets (Level 2)	—	—
Significant unobservable inputs (Level 3)	—	—
	$50,280	$33,851

The amortized cost and estimated fair value of available-for-sale securities by contractual maturity as of December 31, 2012, was as follows (dollars in thousands):

	Amortized Cost	Fair Value
Due in one year or less	$49,614	$49,616
Due in one year to three years	664	664
	$50,278	$50,280

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NOTE 4 – DEFERRED REVENUE

Deferred revenue consisted of the following (dollars in thousands):

	December 31, 2012	June 30, 2012
Amgen Inc.	$—	$11,129
Celgene Corporation	8,043	11,340
DNA BioPharma, Inc.	500	500
Genentech, Inc.	4,648	7,810
Novartis International Pharmaceutical Ltd	17,912	24,788
Total deferred revenue	31,103	55,567
Less: Current portion	(26,534)	(42,339)
Deferred revenue, long-term	$4,569	$13,228

Amgen Inc.

In December 2009, Array granted Amgen the exclusive worldwide right to develop and commercialize our small molecule glucokinase activator, AMG 151/ARRY-403. Under the Collaboration and License Agreement, we were responsible for completing Phase 1 clinical trials on AMG 151. We also conducted further research funded by Amgen to create second generation glucokinase activators. Amgen is responsible for further development and commercialization of AMG 151 and any resulting second generation compounds. The agreement also provides us with an option to co-promote any approved drugs with Amgen in the U.S. with certain limitations.

In partial consideration for the rights granted to Amgen under the agreement, Amgen paid us an up-front fee of $60 million. In June 2012, we received an $8.5 million milestone payment following achievement of a pre-defined patient enrollment milestone in a Phase 2 trial. Amgen has also paid us for research on second generation compounds based on the number of full-time-equivalent scientists who worked on the discovery program. We substantially completed the funded discovery research under the agreement in the second quarter of fiscal 2012.

We are also entitled to receive up to approximately $429 million in additional aggregate milestone payments if all clinical and commercialization milestones specified in the agreement for AMG 151 are achieved. We will also receive royalties on sales of any approved drugs developed under the agreement.

We estimated that our obligations under the agreement would continue until December 31, 2012, at which time they were completed. Therefore, we recognized the up-front fee from the date of the agreement over the resulting three-year period on a straight-line basis. This fee is recorded in license and milestone revenue in the accompanying Condensed Statements of Operations and Comprehensive Loss. We recognized the final $4.9 million and $9.8 million of license revenue under the agreement for each of the three and six months ended December 31, 2012 and 2011, respectively. We recognized the final previously deferred milestone revenue of $581 thousand and $1.3 million under the agreement for the three and six months ended December 31, 2012, respectively. There was no corresponding milestone revenue during the same periods of the prior year.

We record revenue for research performed by our scientists working on second generation compounds and for reimbursed development expenses in collaboration revenue in the accompanying Condensed Statements of Operations and Comprehensive Loss. We recognized $1.1 million and $2.2 million under this agreement for the three and six months ended December 31, 2011, respectively. We do not expect to be paid additional amounts or to recognize additional revenue for research or the up-front fee because we completed most of the required deliverables under this agreement during the second quarter of fiscal 2012 and the up-front fee has been fully recognized.

Either party may terminate the agreement in the event of a material breach of a material obligation under the agreement by the other party upon 90 days prior notice. Amgen may terminate the agreement at any time upon notice of 60 or 90 days depending on the development activities in progress at the time of such notice. The parties have also agreed to indemnify each other for certain liabilities arising under the agreement.

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Novartis International Pharmaceutical Ltd.

Array and Novartis entered into a License Agreement in April 2010, granting Novartis the exclusive worldwide right to co-develop and commercialize MEK162/ARRY-162, as well as other specified MEK inhibitors. Under the agreement, we are responsible for completing the on-going Phase 1b expansion trial of MEK162 in patients with KRAS or BRAF mutant colorectal cancer and for certain further development of MEK162. Novartis is responsible for all other development activities and for the commercialization of products under the agreement, subject to our option to co-detail approved drugs in the U.S.

In consideration for the rights granted to Novartis under the agreement, we received $45 million, comprising an up-front and milestone payment, in the fourth quarter of fiscal 2010. We are entitled to receive up to approximately $413 million in aggregate milestone payments if all clinical, regulatory and commercial milestones specified in the agreement are achieved. In March 2011, we earned a $10.0 million milestone payment which was received in the fourth quarter of fiscal 2011. Novartis will also pay us royalties on worldwide sales of any approved drugs. In addition, as long as we continue to co-develop products under the program, the royalty rate on U.S. sales is significantly higher than the rate on sales outside the U.S. as described below.

We estimate that the obligations under the agreement will continue until April 2014 and, therefore, we are recognizing the up-front fee and milestone payments on a straight-line basis from the date the agreement was signed in April 2010 through that time. These amounts are recorded in license and milestone revenue in the accompanying Condensed Statements of Operations and Comprehensive Loss.

During each of the three and six months ended December 31, 2012 and 2011, we recognized $2.5 million and $5.0 million, respectively, of license revenue and $938 thousand and $1.9 million, respectively, of milestone revenue under this agreement.

The Novartis agreement also contains co-development rights whereby we can elect to pay a percentage share of the combined total development costs. During the first two years of the co-development period, Novartis reimbursed us for 100% of our development costs. In the second quarter of fiscal 2013, we began to pay our percentage share of the combined development costs that have accrued since inception of the program, and that are subject to a maximum amount with annual caps. Annually, we have an option to opt out of paying our percentage share of these costs. If we opt out of paying our share of combined development costs with respect to one or more products, the U.S. royalty rate would then be reduced for any such product based on a specified formula, subject to a minimum that equals the royalty rate on sales outside the U.S.

We record a receivable in prepaid expenses and other current assets in the accompanying Condensed Balance Sheets for the amounts due from Novartis for the reimbursement of our development costs in excess of the annual cap. We record our percentage share of the combined development costs in cost of revenue in the accompanying Condensed Statements of Operations and Comprehensive Loss and accrue these costs in the accompanying Condensed Balance Sheets as a current liability in co-development liability.

Our share of the combined development costs was $2.5 million and $1.4 million during the three months ended December 31, 2012 and 2011, respectively, and $4.3 million and $2.4 million during the six months ended December 31, 2012 and 2011, respectively. We recorded co-development liabilities of $4.0 million and $9.2 million as of December 31, 2012 and June 30, 2012, respectively. We paid Novartis $9.2 million of the accrued co-development liability in the second quarter of fiscal 2013 in accordance with the terms of the agreement. We had related receivables of $1.5 million and $950 thousand in prepaid expenses and other current assets as of December 31, 2012 and June 30, 2012, respectively, for the reimbursable development costs we incurred during the respective preceding three month periods in excess of the annual cap. We incurred development costs for the Array-managed studies subject to the co-development cost sharing arrangement of $1.5 million and $633 thousand during the three months ended December 31, 2012 and 2011, respectively, and $2.7 million and $1.3 million during the six months ended December 31, 2012 and 2011, respectively.

The agreement will be in effect on a product-by-product and country-by-country basis until no further payments are due with respect to the applicable product in the applicable country, unless terminated earlier. Either party may terminate the agreement in the event of an uncured material breach of a material obligation under the agreement by the other party upon 90 days prior notice. Novartis may terminate portions of the agreement following a change in control of Array and may terminate the agreement in its entirety or on a product-by-product basis with 180 days prior notice. Array and Novartis have each further agreed to indemnify the other party for manufacturing or commercialization activities conducted by us under the agreement: negligence, willful misconduct or breach of covenants, warranties or representations made by us under the agreement.

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Celgene Corporation

In September 2007, Array entered into a worldwide strategic collaboration with Celgene focused on the discovery, development and commercialization of novel therapeutics in cancer and inflammation. Under the agreement, Celgene made an up-front payment of $40 million to us in part to provide research funding for activities we conducted. We are responsible for all discovery development through Phase 1 or Phase 2a. Celgene has an option to select a limited number of drugs developed under the collaboration that are directed to up to two of four mutually-selected discovery targets and will receive exclusive worldwide rights to these two drugs, except for limited co-promotional rights in the U.S. Array retains all rights to the programs for which Celgene does not exercise its option.

In June 2009, the agreement was amended to substitute a new discovery target in place of an existing target and Celgene paid us $4.5 million in consideration for the amendment. No other terms of the agreement with Celgene were modified by the amendment. In September 2009, Celgene notified Array that it was waiving its rights to one of the discovery targets under the collaboration, and during fiscal 2012 research on one additional target lapsed. As of December 31, 2012, Celgene retains the option to select both of two remaining targets. The options will expire on the earlier of the completion of Phase 1 or Phase 2a trials for the applicable drug or September 2014.

In January 2012, the agreement was further amended to continue drug discovery activities we were conducting on one of the existing targets. Celgene paid us $1.5 million during fiscal 2012 as compensation for the additional research. We recognized the final $250 thousand of this payment as collaboration revenue during the quarter ended September 30, 2012.

In November 2012, we entered into the third amendment to the agreement to conduct preclinical studies on one or more compounds discovered in the course of research conducted under the January 2012 amendment. We received $3.0 million during the second quarter of fiscal 2013 as partial consideration to conduct the studies, of which we recognized $1.5 million as collaboration revenue during the three months ended December 31, 2012 for related services rendered through that date. We anticipate recognizing the remaining deferred balance during the third quarter of fiscal 2013 as the remaining performance obligations are fulfilled.

Array is entitled to receive, for each drug for which Celgene exercises an option, potential milestone payments of up to $235 million if certain discovery, development and regulatory milestones are achieved and an additional $300 million if certain commercial milestones are achieved. Under the third amendment to the agreement, we agreed to adjust the discovery milestone payable by Celgene relating to the target identified in that amendment if Celgene exercises its option to develop that target early. In November 2010, we earned and subsequently received a $10.0 million milestone payment upon securing an Investigational New Drug (IND) application for one of the programs. We are also entitled to receive royalties on net sales of any drugs.

We regularly review and adjust the estimated period of the discovery obligations to determine the period over which up-front fees and milestone payments will be recognized. Upon execution of the agreement, we estimated that the discovery obligations under the agreement would continue through September 2014 and accordingly began recognizing as revenue the up-front fees received from the date of receipt through September 2014. During the quarter ended September 30, 2011, we estimated that the remaining period for our discovery obligations under the agreement was likely to be only through June 2013. Therefore, in the second quarter of fiscal 2012 we began recognizing the remaining unamortized balance of the up-front payment through this shorter period on a straight-line basis. Throughout the majority of fiscal 2012, research activities associated with the up-front fee were suspended while our drug discovery activities were directed toward the additional funded research discussed above. During the first quarter of fiscal 2013, we began amortizing the remaining deferred balance through January 2014 when we expect to conclude our discovery obligations.

We recognized $2.5 million and $943 thousand in revenue related to the up-front and milestone payments during the three months ended December 31, 2012 and 2011, respectively. We recognized $4.5 million and $2.8 million in revenue related to the up-front and milestone payments during the six months ended December 31, 2012 and 2011, respectively.

We review and adjust, as appropriate, the allocation of research and development expenses under our agreement with Celgene based on the likelihood that Celgene will continue funding development of the programs for which Celgene has an option under the agreement. In the second quarter of fiscal 2011, we concluded that Celgene was likely to continue funding two of the three programs then remaining. Accordingly, beginning October 1, 2010, we began reporting costs associated with the Celgene collaboration as 66.7% to cost of revenue, with the remaining 33.3% to research and development expenses for proprietary programs. This allocation of costs continued until the third quarter of fiscal 2012, when research was active on only one of the remaining programs. At that time, management concluded it is more likely

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than not that Celgene will continue funding that program and pay the Phase 1 milestone and we therefore began recording all costs for our Celgene programs as cost of revenue. As of the second quarter of fiscal 2013, we believe it is more likely than not that Celgene will continue to fund both active programs and we continue to record all of the related program costs to cost of revenue.

Celgene can terminate any drug development program for which it has not exercised an option at any time, provided that it gives us prior notice. In this event, all rights to the program remain with Array and we would no longer be entitled to receive milestone payments for further development or regulatory milestones that it could have achieved had Celgene continued development of the program. Celgene may terminate the agreement in whole, or in part with respect to individual drug development programs for which Celgene has exercised an option, upon six months' written notice to Array. In addition, either party may terminate the agreement, following certain cure periods, in the event of a breach by the other party of its obligations under the agreement.

Genentech, Inc.

In addition to our ongoing collaboration agreements with Genentech, we entered into an additional oncology partnership for the development of each company's small-molecule Checkpoint kinase 1 (Chk-1) program in August 2011. The partnered drugs include Genentech's compound GDC-0425 and Array's compound ARRY-575. Under the terms of the agreement, Genentech acquired a license to Array's compound ARRY-575 and is responsible for all research, clinical development and commercialization activities of the partnered drugs. We received an up-front payment of $28 million during the first quarter of fiscal 2012 and are eligible to receive payments of up to $685 million based on the achievement of clinical and commercial milestones under the agreement. We will also receive up to a double-digit royalty on sales of any drugs resulting from the partnership.

Pursuant to the accounting guidance for revenue recognition for multiple-element arrangements, we determined that Array is obligated to deliver three non-contingent deliverables related to the agreement that meet the separation criteria and therefore are treated as separate units of accounting. These deliverables are (1) the delivery of specified clinical materials for GDC-0575 (ARRY-575) for use in future clinical trials, (2) the transfer of the license and related technology with ongoing regulatory services to assist in filing the IND application and providing supporting data, and (3) activities related to the achievement of a specified milestone.

This agreement also includes a contingent deliverable whereby Genentech could, at its sole option, require us to perform chemical and manufacturing control (CMC) activities for additional drug product or improved processes. This CMC option is not considered a deliverable because the scope, likelihood and timing of the potential services are unclear. Certain critical terms of the services have not yet been negotiated, including the fee that we would receive for the service and Genentech could elect to acquire the drug materials without our assistance either by manufacturing them in-house or utilizing a third-party vendor. Therefore, no portion of the $28 million up-front payment has been allocated to the contingent CMC services that we may be obligated to perform in the future.

The first non-contingent deliverable required Array to prepare specified clinical materials for delivery to Genentech, and we completed this delivery in December 2011, by the date specified in the agreement. The second obligation related to the non-contingent deliverable of assisting in the filing of the IND application was completed as of March 31, 2012. The agreement provides for no general right of return for any non-contingent deliverable. Consequently, the amount of revenue allocated to each deliverable was determined using the relative selling price method under which revenue is allocated to each identified deliverable based on its estimated stand-alone value in relation to the combined estimated stand-alone value of all deliverables. The allocated consideration for each deliverable is then recognized over the related obligation period for that deliverable.

The determination of the stand-alone value for each non-contingent deliverable requires the use of significant estimates by management, including estimates of the time to complete the transfer of related technology and assist in filing the IND. Further, to determine the stand-alone value of the license and initial milestone, we considered the negotiation discussions that lead to the final terms of the agreement, publicly-available data for similar licensing arrangements between other companies and the economic terms of previous collaborations Array has entered into with other partners. Management also considered the likelihood of achieving the initial milestone based on our historical experience with early stage development programs and on the ability to achieve the milestone with either of the two partnered drugs, GDC-0425 or ARRY-575. Taking into account these factors, we allocated a portion of the up-front payment to the first milestone. No portion of any revenue recognized is refundable.

We recognized $1.1 million and $9.9 million in license and milestone revenue and $826 thousand and $2.6 million in collaboration revenue from the partnership with Genentech during the three months ended December 31, 2012 and 2011, respectively. We recognized $2.4 million and $18.2 million in license and milestone revenue and $2.1 million and $5.0 million in collaboration revenue from the partnership with Genentech during the six months ended December 31, 2012 and 2011, respectively.

NOTE 5 – LONG-TERM DEBT

Long-term debt consists of our credit facilities with Deerfield and our term loan with Comerica Bank in the following amounts (dollars in thousands):

	December 31, 2012	June 30, 2012
Deerfield credit facilities	$92,562	$92,562
Comerica term loan	14,700	14,700
Total long-term debt	107,262	107,262
Less: Unamortized discount on Deerfield credit facilities	(12,845)	(15,006)
Long-term debt, net	94,417	92,256
Less: Current portion	—	(150)
	$94,417	$92,106

Deerfield Credit Facilities

As of both December 31, 2012 and June 30, 2012, we had $92.6 million in principal outstanding under the Deerfield credit facilities.

Interest and principal may be repaid at our option at any time with cash or shares of our common stock that have been registered under the Securities Act of 1933, as amended, with certain restrictions. We are required, subject to certain exceptions and conditions, to make payments of principal equal to 15% of certain amounts we receive under new licensing, partnering and other similar arrangements up to the full value of the principal and accrued interest outstanding. We received a $28 million up-front payment from a qualifying new partnership with Genentech in September 2011. As a result in October 2011, we paid $4.2 million to Deerfield which was applied against the principal balance.

Under the terms of the Facility Agreements, a principal payment of $20 million plus accrued interest is due to Deerfield on June 30, 2016. Payment of all other outstanding principal and accrued interest is due to Deerfield on June 30, 2015. If our total cash, cash equivalents and marketable securities at the end of a fiscal quarter falls below $20 million, or another specified event of default under the Facility Agreements occurs, all amounts outstanding under the credit facilities become immediately due and payable.

Embedded Derivatives

The credit facilities contain two embedded derivatives: (1) a variable interest rate structure that is based on our available cash, cash equivalents and marketable securities; and (2) Deerfield's right to accelerate the loan upon certain non-qualifying changes of control of Array, which is considered a significant transaction contingent put option. We refer to these embedded derivatives collectively as the "embedded derivatives."

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The forecasts used by management in determining the estimated fair value of the embedded derivatives are inherently subjective and may not reflect actual results, although management believes the assumptions upon which they are based are reasonable. Management will continue to assess the assumptions used in its determination of the fair value of the embedded derivatives. Future changes affecting these assumptions could materially affect the estimated fair value of the embedded derivatives resulting in a corresponding adjustment to the reported results of operations in future periods. For example, the combined value of the embedded derivatives as of December 31, 2012 of $479 thousand is largely based on the assumption that our ending monthly balance of total cash and marketable securities could fall to between $40 million and $50 million nine times during the remaining 42 months of the facility. The table below summarizes the potential impact of the use of two other assumptions relating to the periods during which our total cash and marketable securities balances are at the levels shown in the table compared to the assumptions used by management as of December 31, 2012, and the resulting estimated increases to the value of the embedded derivatives in the accompanying Condensed Balance Sheet and interest expense in the Condensed Statement of Operations and Comprehensive Loss that would have been reported in the current quarter if the assumptions reflected in the alternate scenario had been used (dollars in thousands):

Cash Balance	Actual assumption used	Scenario 1	Scenario 2
	Assumed Number of Months		
$50 million or greater	33	28	23
Between $40 million and $50 million	9	12	12
Between $30 million and $40 million	—	2	7
Less than $30 million	—	—	—
Effective interest rate	7.7 %	8.0 %	8.5 %
Fair value of embedded derivatives	$479	$990	$1,918
Additional interest expense that would be charged in the quarter	$—	$511	$1,439

Fair Value of the Debt

We estimate the fair value of the Deerfield debt using a combination of a discounted cash flow analysis and the Black Derman Toy interest rate model that incorporates the estimates discussed above for the embedded derivatives. The fair value of the debt was determined to be $87.2 million and $73.4 million at December 31, 2012 and June 30, 2012, respectively. The estimated fair value of the Deerfield debt was classified using the Level III, significant unobservable, inputs discussed above.

Summary of Interest Expense

Interest expense for the Deerfield credit facilities follows (dollars in thousands):

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
Simple interest	$1,609	$1,586	$3,218	$3,274
Amortization of the transaction fees	59	60	119	123
Amortization of the debt discounts	1,090	890	2,161	1,959
Change in fair value of the embedded derivatives	(48)	208	(177)	193
Loss on early principal payment of debt	—	942	—	942
Total interest expense on the Deerfield credit facilities	$2,710	$3,686	$5,321	$6,491

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Comerica Term Loan

As of December 31, 2012, the term loan with Comerica Bank had an interest rate of 3.25% per annum. The following table shows actual interest paid and amortization of loan transaction fees that were charged to interest expense (dollars in thousands):

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
Simple interest	$123	$123	$244	$247
Amortization of the transaction fees	27	27	54	54
Total interest expense on Comerica loan	$150	$150	$298	$301

In December 2012, the Loan and Security Agreement with Comerica was amended to extend the maturity date of the term loan by 12 months to October 2014 and the maturity date of the revolving line of credit to June 2014. Pursuant to the terms of the agreement, a principal payment of $14.7 million is due to Comerica at maturity in October 2014.

The estimated fair value of the term loan of $14.7 million was determined using a discounted cash flow model as of December 31, 2012 and June 30, 2012. The estimated fair value of the Comerica loan was classified using Level II, observable inputs other than quoted prices in active markets.

Commitment Schedule

Array is required to make principal payments under the Deerfield credit facilities and the Comerica term loan as follows (dollars in thousands):

For the twelve months ended December 31,	
2013	$—
2014	14,700
2015	72,562
2016	20,000
2017	—
	$107,262

NOTE 6 – SHARE-BASED COMPENSATION EXPENSE

All share-based payments to employees are recognized in the Condensed Statements of Operations and Comprehensive Loss based on the fair value of the award on the grant date. Share-based compensation arrangements include stock option grants under the Array BioPharma Amended and Restated Stock Option and Incentive Plan and the ability to purchase common stock at a discount under the Employee Stock Purchase Plan, or ESPP. The fair value of all stock options granted by Array and shares issued under the ESPP is estimated on the date of grant using the Black-Scholes option-pricing model. We recognize share-based compensation expense on a straight-line basis over the vesting term of stock option grants and report it as either cost of revenue, research and development for proprietary programs or general and administrative, as appropriate. See Note 13 – Employee Compensation Plans to our audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, for more information about the assumptions we used under this valuation methodology. During the six months ended December 31, 2012, we did not make any material changes to these assumptions.

The table below shows options issued to purchase additional shares and compensation expense for the periods indicated (dollars in thousands):

	Three Months Ended December 31,		Six Months Ended December 31,	
	2012	2011	2012	2011
Shares of stock authorized to be issued under new options	159,600	121,000	421,800	271,600
Stock option compensation expense	$693	$508	$1,357	$1,051
ESPP compensation expense	$74	$80	$205	$104

As of December 31, 2012, there was $4.3 million of unrecognized compensation expense, including the impact of expected forfeitures, for unvested share-based compensation awards granted under our equity plans, which we expect to recognize over a weighted-average period of 2.8 years.

NOTE 7 – SHAREHOLDERS’ EQUITY

Common Stock

On August 31, 2012, the Board of Directors approved an amendment, subject to stockholder approval, to our Amended and Restated Certificate of Incorporation increasing the number of shares of Common Stock we are authorized to issue from 120 million to 220 million shares. On October 24, 2012, our stockholders approved this amendment at the annual stockholders meeting. The amendment was filed with the secretary of the State of Delaware and became effective on October 25, 2012.

During the second quarter of fiscal 2013, we sold 20.7 million shares of our common stock in an offering to the public pursuant to an effective registration statement on Form S-3 at a price to the public of $3.65 per share. We received net proceeds from the sale of the shares, after underwriting discounts and commissions and related offering expenses, of approximately $70.9 million. We intend to use the net proceeds from this offering to fund research and development efforts, including clinical trials for our proprietary candidates, and for general corporate purposes.

Preferred Stock

On May 3, 2011, we issued and sold to Deerfield 10,135 shares of our series B convertible preferred stock, for an aggregate purchase price of $30 million, pursuant to the terms of a Securities Purchase Agreement as discussed in Note 8 – Long-Term Debt in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012 filed with the Securities and Exchange Commission on August 16, 2012. Each share of series B convertible preferred stock was convertible into 1,000 shares of common stock at the election of Deerfield. During fiscal 2012, Deerfield converted 7,414.188 shares of series B convertible preferred stock into 7,414,188 shares of common stock. As of June 30, 2012, there were 2,720.812 shares of series B convertible preferred stock outstanding. During the quarter ended September 30, 2012, Deerfield converted its remaining 2,720.812 shares of series B convertible preferred stock into 2,720,812 shares of common stock. The conversions were non-cash transactions effected pursuant to the terms of the Certificate of Designation of Preferences, Rights and Limitations of the series B convertible preferred stock. As of December 31, 2012, there were no outstanding shares of preferred stock.

NOTE 8 – EMPLOYEE BONUS

We have an annual performance bonus program for our employees in which employees may receive a bonus payable in cash or in shares of common stock if we meet certain financial, discovery, development and partnering goals during a fiscal year. The bonus is typically paid in the second quarter of the next fiscal year, and we accrue an estimate of the expected aggregate bonus in accrued compensation and benefits in the accompanying Condensed Balance Sheets.

We had $2.6 million and $4.4 million accrued for our annual performance bonus program as of December 31, 2012 and June 30, 2012, respectively.

On October 4, 2012, we paid bonuses to approximately 250 eligible employees having an aggregate value of $4.3 million under the fiscal 2012 Performance Bonus Program by issuing a total of 493,413 shares of our common stock and a payment of cash to satisfy related withholding taxes.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, including statements about our expectations related to the progress and success of drug discovery activities conducted by Array and by our collaborators, our ability to obtain additional capital to fund our operations, changes in our research and development spending, realizing new revenue streams and obtaining future out-licensing partnership or collaboration agreements that include up-front, milestone and/or royalty payments, our ability to realize up-front milestone and royalty payments under our existing or any future agreements, future research and development spending and projections relating to the level of cash we expect to use in operations, our working capital requirements and our future headcount requirements. In some cases, forward-looking statements can be identified by the use of terms such as "may," "will," "expects," "intends," "plans," "anticipates," "estimates," "potential," or "continue," or the negative thereof or other comparable terms. These statements are based on current expectations, projections and assumptions made by management and are not guarantees of future performance. Although we believe that the expectations reflected in the forward-looking statements contained herein are reasonable, these expectations or any of the forward-looking statements could prove to be incorrect and actual results could differ materially from those projected or assumed in the forward-looking statements. Our future financial condition, as well as any forward-looking statements are subject to significant risks and uncertainties, including but not limited to the factors set forth under the heading "Risk Factors" in Item 1A of the Annual Report on Form 10-K for the fiscal year ended June 30, 2012 we filed with the Securities and Exchange Commission on August 16, 2012, under the heading "Risk Factors" in Item 1A under Part II of this Quarterly Report, and in other reports we file with the Securities and Exchange Commission. All forward-looking statements are made as of the date hereof and, unless required by law, we undertake no obligation to update any forward-looking statements.

The following discussion of our financial condition and results of operations should be read in conjunction with the financial statements and notes to those statements included elsewhere in this Quarterly Report. The terms "we," "us," "our" and similar terms refer to Array BioPharma Inc.

Overview

We are a biopharmaceutical company focused on the discovery, development and commercialization of targeted small molecule drugs to treat patients afflicted with cancer. During 2013, we expect to make substantial progress in generating data to inform registration study decisions for our wholly-owned hematology programs, ARRY-520 and ARRY-614. Array-invented MEK162 will be tested in a Phase 3 trial in NRAS melanoma which is scheduled to start in April 2013, as well as BRAF mutant melanoma later in 2013 (with Novartis). Also, AstraZeneca recently announced a potential start of a Phase 3 trial with Array-invented selumetinib in non-small cell lung cancer during the second half of 2013.

Our most advanced wholly-owned clinical stage drugs include:

Proprietary Program	Indication	Clinical Status
1. ARRY-520	Kinesin spindle protein, or KSP, inhibitor for multiple myeloma	Phase 2
2. ARRY-614	p38/Tie2 dual inhibitor for myelodysplastic syndromes, or MDS	Phase 1
3. ARRY-797	p38 inhibitor for pain	Phase 2
4. ARRY-502	CRTh2 antagonist for asthma	Phase 2

In 2012, we made the strategic decision to focus internally on hematology/oncology moving forward. With our progress on ARRY-614 for myelodysplastic syndromes and ARRY-520 for multiple myeloma, we believe hematology/oncology is the area of greatest opportunity for Array and where we intend to concentrate our resources and build on our capabilities in fiscal 2013 and beyond.

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In addition, we have 10 partner-funded clinical programs:

Drug Candidate	Indication	Partner	Clinical Status
1. Selumetinib	MEK inhibitor for cancer	AstraZeneca, PLC	Phase 2
2. MEK162	MEK inhibitor for cancer	Novartis International Pharmaceutical Ltd.	Phase 2
3. Danoprevir	Hepatitis C virus protease inhibitor	InterMune (now owned by Roche Holding AG)	Phase 2
4. AMG 151	Glucokinase activator for Type 2 diabetes	Amgen Inc.	Phase 2
5. ARRY-543/ASLAN001	HER2/EGFR inhibitor for gastric cancer	ASLAN Pharmaceuticals Pte Ltd.	Phase 2
6. GDC-0068	AKT inhibitor for cancer	Genentech Inc.	Phase 2
7. LY2603618	Chk-1 inhibitor for cancer	Eli Lilly and Company	Phase 2
8. GDC-0575 and GDC-0425	Chk-1 inhibitors for cancer	Genentech Inc.	Phase 1b
9. ARRY-382	cFMS inhibitor for cancer	Celgene Corporation	Phase 1
10. VTX-2337	Toll-like receptor for cancer	VentiRx Pharmaceuticals, Inc.	Phase 2

We also have a portfolio of proprietary and partnered drug discovery programs generated by our internal discovery efforts. Our internal drug discovery programs include inhibitors that target Trk receptors for the treatment of pain and G-protein coupled receptor 119 for the treatment of diabetes. We may choose to out-license select promising candidates through research partnerships.

Any information we report about the development plans or the progress or results of clinical trials or other development activities of our partners is based on information that is publicly-disclosed.

Our significant collaborators include:

- Amgen – We entered into a worldwide strategic collaboration with Amgen in December 2009 to develop and commercialize our glucokinase activator, AMG 151, which is currently in Phase 2 development for Type 2 diabetes, and to discover potential back-up compounds for AMG 151.

- ASLAN Pharmaceuticals – We entered into a collaboration and license agreement with ASLAN Pharmaceuticals in July 2011 to develop Array's HER2 / EGFR inhibitor, ARRY-543, or ASLAN001, which is currently in a Phase 2 clinical trial in patients with gastric cancer.

- AstraZeneca – In December 2003, we entered into a collaboration and license agreement with AstraZeneca under which AstraZeneca received a license to three of our MEK inhibitors for cancer, including selumetinib, which is currently in multiple Phase 2 clinical trials.

- Celgene – We entered into a worldwide strategic collaboration agreement with Celgene in September 2007 focused on the discovery, development and commercialization of novel therapeutics in cancer and inflammation. The most advanced drug is ARRY-382, a cFMS inhibitor for cancer, which is currently in a Phase 1 clinical trial.

- Genentech – We entered into a worldwide strategic collaboration agreement with Genentech in January 2003, which was expanded in 2005, 2008 and 2009, and is focused on the discovery, development and commercialization of novel therapeutics. The most advanced drug is GDC-0068, an AKT inhibitor for cancer, which is currently in a Phase 2 trial.

In August 2011, we entered into an oncology partnership with Genentech for the development of each company's small molecule Checkpoint kinase 1 (Chk-1) program. The programs include Genentech's compound GDC-0425 (RG7602) and Array's compound, GDC-0575, both of which are in Phase 1 clinical trials in patients with cancer.

- InterMune (program acquired by Roche) – We entered into a collaboration with InterMune in 2002, which resulted in the joint discovery of danoprevir, a novel small molecule inhibitor of the Hepatitis C Virus NS3/4A protease. Roche Holding AG acquired danoprevir from InterMune in 2010. Danoprevir is currently in Phase 2b clinical trials.

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- Novartis – We entered into a worldwide strategic collaboration with Novartis in April 2010 to develop and commercialize our MEK inhibitor, MEK162, and other MEK inhibitors identified in the agreement. MEK162 is currently in numerous Phase 1b and Phase 2 clinical trials in patients with cancer.

We have built our clinical development and drug discovery programs through spending $548.3 million from our inception in 1998 through December 31, 2012. During the first half of fiscal 2013, we spent $27.5 million in research and development expenses for proprietary programs. In fiscal 2012, we spent $56.7 million in research and development expenses for proprietary programs, compared to $63.5 million and $72.5 million for fiscal years 2011 and 2010, respectively.

We have received a total of $587.6 million in research funding and in up-front and milestone payments from our partnerships and collaborations from inception through December 31, 2012, including $133 million in initial payments from our strategic agreements with Amgen, Genentech and Novartis that we entered into over the past three years. With our other existing partnered programs, Array is entitled to receive a total of over $3 billion in additional potential milestone payments if we or our partners achieve the drug discovery, development and commercialization objectives detailed in those agreements. We also have the potential to earn royalties on any resulting product sales or share in the proceeds from development or commercialization arrangements resulting from 10 drug research and development programs.

Fiscal Periods

Our fiscal year ends on June 30. When we refer to a fiscal year or quarter, we are referring to the year in which the fiscal year ends and the quarters during that fiscal year. Therefore, fiscal 2013 refers to the fiscal year ending June 30, 2013, and the second or current quarter refers to the quarter ended December 31, 2012.

Business Development and Partner Concentrations

We currently license or partner certain of our compounds and/or programs and enter into partnerships directly with pharmaceutical and biotechnology companies through opportunities identified by our business development group, senior management, scientists and customer referrals.

In general, our collaborators may terminate their collaboration agreements with 90 to 180 days' prior notice. Our agreement with Genentech can be terminated with 120 days' notice. Celgene may terminate its agreement with us with six months' notice. Amgen may terminate its agreement with us at any time upon notice of 60 or 90 days depending on the development activities in progress at the time of such notice. Novartis may terminate portions of the agreement following a change in control of Array and may terminate the agreement in its entirety or on a product-by-product basis with 180 days prior notice.

Additional information related to the concentration of revenue among our partners is reported in Note 2 – Segments, Geographic Information and Significant Partnerships to the financial statements included elsewhere in this Quarterly Report.

All of our partnership and collaboration agreements are denominated in U.S. dollars.

Critical Accounting Policies and Estimates

Management's discussion and analysis of financial condition and results of operations are based upon our accompanying financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, as well as the disclosure of contingent assets and liabilities. We regularly review our estimates and assumptions. These estimates and assumptions, which are based upon historical experience and on various other factors believed to be reasonable under the circumstances, form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Reported amounts and disclosures may have been different had management used different estimates and assumptions or if different conditions had occurred in the periods presented.

Revenue Recognition

We recognize revenue based on four criteria, each of which must be met in order to recognize revenue for the performance of services or the shipment of products. Revenue is recognized when (a) persuasive evidence of an arrangement exists, (b) products are delivered or as services are rendered, (c) the sales price is fixed or determinable and (d) collectability is reasonably assured.

We follow ASC 605-25 "Revenue Recognition – Multiple-Element Arrangements" to determine the recognition of revenue under partnership and collaboration agreements that include multiple elements, including research and development services, achievement of development and commercialization milestones and drug product manufacturing. This standard provides guidance on the accounting for arrangements involving the delivery of multiple elements when the delivery of separate units of accounting occurs in different reporting periods. This standard addresses the determination of the units of accounting for multiple-element arrangements and how the arrangement's consideration should be allocated to each unit of accounting. We adopted this accounting standard on a prospective basis for all multiple-element arrangements entered into on or after July 1, 2010, and for any multiple-element arrangements that were entered into prior to July 1, 2010, but materially modified on or after July 1, 2010. The adoption of this standard may result in revenue recognition patterns for future agreements that are materially different from the recognition of revenue under partnership and collaboration arrangements entered into prior to this date.

We evaluate the deliverables to determine if they meet the separation criteria under the standard and have stand-alone value and we allocate revenue to the elements based on their relative selling prices. We treat deliverables in an arrangement that do not meet the separation criteria in this standard as a single unit of accounting, generally applying applicable revenue recognition guidance for the final deliverable to the combined unit of accounting.

We recognize revenue from non-refundable up-front payments and license fees on a straight-line basis over the term of performance under the agreement. When the performance period is not specifically identifiable from the agreement, we estimate the performance period based upon provisions contained within the agreement, such as the duration of the research or development term, the existence, or likelihood of achievement of development commitments and any other significant commitments. For agreements entered into prior to July 1, 2010, the performance period is generally the estimated research or development term. For agreements entered into on or after this date, the performance period is measured as the time between the execution date and the completion of the inseparable technology transfer, which is typically a shorter period, generally up to six months.

We defer the up-front payments and record them as deferred revenue upon receipt, pending recognition. The deferred portions of payments are classified as a short-term or long-term liability in the accompanying Condensed Balance Sheets, depending on the period during which revenue is expected to be recognized.

Most of our agreements provide for milestone payments. In certain cases, we recognize all or a portion of each milestone payment as revenue when the specific milestone is achieved based on the applicable percentage earned of the estimated research or development effort, or other performance obligations that have elapsed, to the total estimated research and/or development effort. In other cases, when the milestone payment is attributed to our future development obligations, we recognize the revenue on a straight-line basis over the estimated remaining development effort. We record milestone payments as deferred revenue upon receipt until recognized.

We periodically review the expected performance periods under each of our agreements that provide for non-refundable up-front payments, license fees and milestone payments. We adjust the amortization periods when appropriate to reflect changes in assumptions relating to the duration of expected performance periods. We could accelerate revenue recognition for non-refundable up-front payments, and license fees and milestone payments in the event of early termination of programs. Alternatively, we could decelerate such revenue recognition if programs are extended. While changes to such estimates have no impact on our reported cash flows, our reported revenue may be significantly influenced by our estimates of the period over which our obligations are expected to be performed and, therefore, over which revenue is recognized.

Long-term Debt and Embedded Derivatives

The terms of our long-term debt are discussed in detail in Note 5 – Long-term Debt to the financial statements in this Quarterly Report on Form 10-Q and in Note 8 – Long-Term Debt to the financial statements in our Annual Report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the SEC on August 16, 2012. The accounting for these arrangements is complex and is based upon significant estimates by management. We review all debt agreements to determine the appropriate accounting treatment when the agreement is entered into and review all amendments to determine if the changes require accounting for the amendment as a modification of the debt, or as an extinguishment and issuance of new debt.

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Recent Accounting Pronouncements

In June 2011, the FASB issued FASB ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income in U.S. GAAP and IFRS. This ASU provides companies the option to present the components of net income and other comprehensive income either as one continuous statement of comprehensive income or as two separate but consecutive statements. It eliminates the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity. The provisions of this new guidance are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We adopted this disclosure standard in the first quarter of fiscal 2013 and it did not have a material impact on our results of operations.

Other recent accounting pronouncements issued by the FASB (including its Emerging Issues Task Force) and the SEC did not or are not believed by management to have a material impact on our present or future financial statements.
Results of Operations

License and Milestone Revenue

License and milestone revenue is combined and consists of up-front license fees and ongoing milestone payments from partners and collaborators.

Below is a summary of our license and milestone revenue (dollars in thousands):

	Three Months Ended December 31,		Change 2012 vs. 2011		Six Months Ended December 31,		Change 2012 vs. 2011	
	2012	2011	$	%	2012	2011	$	%
License revenue	$9,740	$16,814	$(7,074)	(42)%	$19,073	$30,896	$(11,823)	(38)%
Milestone revenue	4,276	2,381	1,895	80%	7,419	6,761	658	10%
Total license and milestone revenue	$14,016	$19,195	$(5,179)	(27)%	$26,492	$37,657	$(11,165)	(30)%

License revenue decreased during the three and six month periods ended December 31, 2012, compared to the same periods in the prior year primarily because the majority of the revenue under our Chk-1 license agreement with Genentech was recognized during fiscal 2012 and we had no comparable new revenue in fiscal 2013. The decrease was slightly offset by additional revenue recognized during fiscal 2013 from the Celgene up-front payment for which recognition was suspended during part of the prior year as discussed under Note 4 – Deferred Revenue - Celgene.

Milestone revenue increased during the three and six month periods ended December 31, 2012, compared to the same periods in the prior year. The increase was primarily due to the recognition of a $1.5 million milestone payment received from VentiRx during the current quarter, as well as revenue recognized under the previously deferred portion of the $8.5 million milestone payment received from Amgen during the fourth quarter of fiscal 2012 for which we did not have corresponding revenue in the first half of the prior year. Largely offsetting the increases during the six-month period was reduced milestone revenue under our collaboration with Genentech from which we recognized $3.0 million in the first half of fiscal 2012 compared to $250 thousand in the first half of fiscal 2013.

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Collaboration Revenue

Collaboration revenue consists of revenue for our performance of drug discovery and development activities in collaboration with partners, which include development of proprietary drug candidates we out-license, as well as screening, lead generation and lead optimization research, custom synthesis and process research and, to a small degree, the development and sale of chemical compounds.

Below is a summary of our collaboration revenue (dollars in thousands):

	Three Months Ended December 31,		Change 2012 vs. 2011		Six Months Ended December 31,		Change 2012 vs. 2011	
	2012	2011	$	%	2012	2011	$	%
Collaboration revenue	$4,361	$4,033	$328	8 %	$7,718	$7,701	$17	— %

Collaboration revenue increased during the three and six month periods ended December 31, 2012, compared to the prior year due to our new collaborations with DNA BioPharma and Clovis Oncology, as well as the additional funded research under our collaboration with Celgene. Largely offsetting the increases were reduced revenues under our collaboration with Genentech and the completion of our funded discovery research under our collaboration with Amgen.

Cost of Revenue

Cost of revenue represents costs attributable to discovery and development including preclinical and clinical trials we may conduct for or with our collaborators and the cost of chemical compounds sold from our inventory. These costs consist mainly of compensation, associated fringe benefits, share-based compensation, preclinical and clinical outsourcing costs and other partnership-related costs, including supplies, small tools, travel and meals, facilities, depreciation, recruiting and relocation costs and other direct and indirect chemical handling and laboratory support costs.

Below is a summary of our cost of revenue (dollars in thousands):

	Three Months Ended December 31,		Change 2012 vs. 2011		Six Months Ended December 31,	Change 2012 vs. 2011
	2012	2011	$	1.5		

120.0

OU Spirit

2009
Woodward, OK
44
Wind
40.6
%

2.3

101.2

Total Generating Capability (wind stations)
448.7

(A) 2013 Capacity Factor = 2013 Net Actual Generation / (2013 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units are used when additional short-term capacity is required.
(C) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(D) Represents OG&E's 77 percent ownership interest in the McClain Plant.

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At December 31, 2013, OG&E's transmission system included: (i) 51 substations with a total capacity of 12.0 million kilovolt-amps and 4,589 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.4 million kilovolt-amps and 278 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 353 substations with a total capacity of 9.5 million kilovolt-amps, 29,144 structure miles of overhead lines, 2,239 miles of underground conduit and 10,617 miles of underground conductors in Oklahoma and (ii) 33 substations with a total capacity of 1.0 million kilovolt-amps, 2,775 structure miles of overhead lines, 232 miles of underground conduit and 696 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73102. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, service centers, fleet and equipment service facilities, operation support and other properties.
During the three years ended December 31, 2013, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.3 billion and gross retirements were $249.0 million. These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to 24.9 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2013.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as set forth below, under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K and in Notes 15 and 16 of Notes to Consolidated Financial Statements, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

1. Patent Infringement Case. On September 16, 2011, TransData, Inc., a Texas corporation, sued OG&E in the Western District of Oklahoma, accusing OG&E of infringing three of their U.S. patents by using OG&E's General Electric "smart" meters with Silver Spring Networks wireless modules. The complaint seeks a judgment of infringement, unspecified damages, a permanent injunction, costs and attorneys fees. OG&E was served with the complaint on September 21, 2011 and has notified both General Electric and Silver Springs Network of the lawsuit and its intent to seek indemnity from those companies for any damages that it may incur from this lawsuit. TransData, Inc. sought to consolidate its OG&E lawsuit with similar lawsuits in the Eastern District of Texas, however, on December 13, 2011, the TransData, Inc. cases were consolidated in the Western District of Oklahoma. OG&E has filed a motion for extension of time to answer the complaint. On December 30, 2011, OG&E and General Electric agreed to terms for General Electric to provide OG&E with an unqualified defense in the matter and to indemnify OG&E for costs, expenses and damages awarded against OG&E subject to a reservation of rights. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this action and believes that its ultimate resolution will not be material to the Company's consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not Applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's Common Stock is listed for trading on the New York Stock Exchange under the ticker symbol "OGE." Quotes may be obtained in daily newspapers where the common stock is listed as "OGE Engy" in the New York Stock Exchange listing table. The following table gives information with respect to price ranges, as reported in The Wall Street Journal as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

2014	Dividend Paid	Price High	Low
First Quarter (through February 20)	$0.2250	$36.25	$32.91
2013			
First Quarter	$0.2088	$35.08	$27.70
Second Quarter	0.2088	36.59	32.20
Third Quarter	0.2088	39.55	33.85
Fourth Quarter	0.2088	40.00	32.85
2012			
First Quarter	$0.1963	$28.77	$25.62
Second Quarter	0.1963	27.66	25.12
Third Quarter	0.1963	28.25	25.30
Fourth Quarter	0.1963	30.11	27.18

At the Company's December 2013 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.2250 per share from $0.20875 per share effective with the Company's first quarter 2014 dividend.

The number of record holders of the Company's Common Stock at December 31, 2013, was 17,828. The book value of the Company's Common Stock at December 31, 2013 was $15.29.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. Because the Company is a holding company and conducts all of its operations through its subsidiaries and equity affiliates, the Company's cash flow and ability to pay dividends will be dependent on the earnings and cash flows of its subsidiaries and equity affiliates and the distribution or other payment of those earnings to the Company in the form of dividends or distributions, or in the form of repayments of loans or advances to it. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock, and from distributions paid by Enable. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding, any covenants of OG&E's certificate of incorporation and OG&E's debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. The Company's ability to receive distributions on its limited partnership interest in Enable is subject to Enable's cash available for distribution, the terms of its limited partnership agreement, and the covenants of Enable's debt instruments limiting the ability of Enable to pay distributions.

Issuer Purchases of Equity Securities

The following table contains information about the Company's purchases of its common stock during the fourth quarter of 2013.

Period	Total Number of Shares Purchased		Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
10/1/13 - 10/31/13	—		$—	N/A	N/A
11/1/13 - 11/30/13	346	(A)	$34.68	N/A	N/A
12/1/13 - 12/31/13	460	(A)	$34.18	N/A	N/A

(A) These shares of restricted stock were returned to the Company to satisfy tax liabilities.
N/A – not applicable

Item 6. Selected Financial Data

HISTORICAL DATA Year ended December 31 SELECTED FINANCIAL DATA (In millions, except per share data)	2013	2012	2011	2010	2009
Results of Operations Data:					
Operating revenues	$2,867.7	$3,671.2	$3,915.9	$3,716.9	$2,869.7
Cost of sales	1,428.9	1,918.7	2,277.9	2,187.4	1,557.7
Operating expenses	885.3	1,075.6	991.3	935.6	820.1
Operating income	553.5	676.9	646.7	593.9	491.9
Equity in earnings of unconsolidated affiliates	101.9	—	—	—	—
Allowance for equity funds used during construction	6.6	6.2	20.4	11.4	15.1
Other income	31.8	17.6	19.8	13.7	28.9
Other expense	22.2	16.5	21.7	17.9	16.3
Interest expense	147.5	164.1	140.9	139.7	137.4
Income tax expense	130.3	135.1	160.7	161.0	121.1
Net income	393.8	385.0	363.6	300.4	261.1
Less: Net income attributable to noncontrolling interests	6.2	30.0	20.7	5.1	2.8
Net income attributable to OGE Energy	$387.6	$355.0	$342.9	$295.3	$258.3
Basic earnings per average common share attributable to OGE Energy common shareholders	$1.96	$1.80	$1.75	$1.51	$1.34
Diluted earnings per average common share attributable to OGE Energy common shareholders	$1.94	$1.79	$1.73	$1.49	$1.33
Dividends declared per common share	$0.85125	$0.79750	$0.75875	$0.73125	$0.71375
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$6,672.8	$8,344.8	$7,474.0	$6,464.4	$5,911.6
Total assets	$9,134.7	$9,922.2	$8,906.0	$7,669.1	$7,266.7
Long-term debt	$2,400.1	$2,848.6	$2,737.1	$2,362.9	$2,088.9
Total stockholders' equity	$3,037.1	$3,072.4	$2,819.3	$2,400.0	$2,060.8
Capitalization Ratios (A)					
Stockholders' equity	55.9%	51.9%	50.7%	50.4%	46.4%
Long-term debt	44.1%	48.1%	49.3%	49.6%	53.6%
Ratio of Earnings to Fixed Charges (B)					
Ratio of earnings to fixed charges	4.30	3.94	4.12	4.02	3.38

(A) Capitalization ratios = [Total stockholders' equity / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)].

(B) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of pre-tax income plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. For a discussion of the change in the Company’s business segments due to the formation of Enable, see Note 14 of Notes to Consolidated Financial Statements. For periods prior to May 1, 2013, the Company consolidated Enogex Holdings in its Condensed Consolidated Financial Statements.

Effective May 1, 2013, OGE Energy, the ArcLight group and CenterPoint Energy, Inc., formed Enable Midstream Partners, LP to own and operate the midstream businesses of OGE Energy and CenterPoint. In the formation transaction, OGE Energy and ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy began accounting for its interest in Enable using the equity method of accounting. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable. OGE Energy also owns a 60 percent interest in any incentive distribution rights in Enable. Incentive distribution rights are expected to entitle the holder to increasing percentages, up to a maximum of 50 percent, of the cash distributed by Enable in excess of the target quarterly distributions to be set in connection with Enable’s initial public offering.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment consists of the Company's investment in Enable. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Company completed a 2-for-1 stock split of the Company's common stock effective July 1, 2013. All share and per share amounts within this Form 10-K reflect the effects of the stock split.

Overview

Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E expects to maintain a diverse generation portfolio while remaining environmentally responsible. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. The

Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the SPP.

Enable's primary business objective is to practice operational excellence and to grow its business responsibly, increasing the amount of cash distributions made to its unitholders over time while maintaining financial stability. Strategies to accomplish this objective include capitalizing on organic growth opportunities and leveraging the scale of its existing assets, utilizing long-term, fee-based contracts to minimize direct commodity price exposure and maintaining strong customer relationships to attract new volumes and expand beyond its existing footprint and business lines. Enable also plans to grow through accretive acquisitions and disciplined development.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends of approximately 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

Summary of Operating Results

2013 compared to 2012. Net income attributable to OGE Energy was $387.6 million, or $1.94 per diluted share, in 2013 as compared to $355.0 million, or $1.79 per diluted share, in 2012. The increase in net income attributable to OGE Energy of $32.6 million, or 9.2 percent, or $0.15 per diluted share, in 2013 as compared to 2012 was primarily due to:

- an increase in net income at OG&E of $12.3 million, or 4.4 percent, or $0.06 per diluted share of the Company's common stock, driven by higher gross margin primarily related to increased wholesale transmission revenue and lower other operation and maintenance expense, partially offset by higher interest expense related to the issuance of debt in May 2013;
- an increase in net income at OGE Holdings of $25.8 million, or 34.8 percent, or $0.13 per diluted share of the Company's common stock, due partially to the accretive effect to OGE Holdings of its investment in Enable since May 1, 2013 and a reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of Enable. Also contributing to the increase was the performance of Enogex for the first four months of 2013. Compared to the same period of 2012, earnings were higher for Enogex due to increased gathering rates and volumes and inlet processing volumes associated with its expansion projects and gas gathering assets acquired in August 2012. These increases were partially offset by lower NGLs prices, lower keep-whole processing spreads and the contract conversion of the Texas production volumes of one of Enogex's five largest customers from keep-whole to fixed-fee; and
- a decrease in net income at OGE Energy of $5.5 million, or $0.04 per diluted share of the Company's common stock, primarily due to transaction expenses related to the formation of Enable as discussed in Note 3 of Notes to Condensed Consolidated Financial Statements.

2012 compared to 2011. Net income attributable to OGE Energy was $355.0 million, or $1.79 per diluted share, in 2012 as compared to $342.9 million, or $1.73 per diluted share, in 2011. The increase in net income attributable to OGE Energy of $12.1 million, or 3.5 percent, or $0.06 per diluted share, in 2012 as compared to 2011 was primarily due to:

- an increase in net income at OG&E of $17.0 million, or 6.5 percent, or $0.09 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. The increase in gross margin was partially offset by higher depreciation and amortization expense related to additional assets being placed in service and lower allowance for equity funds used during construction related to higher levels of construction costs for the Crossroads wind farm in 2011;
- an increase in net income of Enogex LLC of $0.7 million, which was offset by an $8.9 million increase in net income attributable to noncontrolling interests, resulting in a decrease in net income attributable to OGE Holdings

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of $8.2 million, or 9.9 percent, or $0.04 per diluted share of the Company's common stock. The increase in net income attributable to noncontrolling interests reflected a reduction in the Company's ownership percentage of Enogex LLC due to increased capital contributions from the ArcLight group. The improvement in Enogex LLC's net income reflected higher operating income on increased gathering rates and volumes associated with ongoing expansion projects, increased volumes from gas gathering assets acquired in November 2011 and August 2012 and increased inlet volumes, which were partially offset by lower average natural gas and NGLs prices. Also contributing to the favorable results were a higher gain on insurance proceeds in 2012 and an impairment charge related to the Atoka processing plant in 2011 which did not occur in 2012. These improvements were partially offset by increased depreciation and amortization expense due to additional assets being placed in service throughout 2011 and 2012, higher other operations and maintenance expenses, and higher taxes other than income related to sales taxes on assets acquired; and

- an increase in net income at OGE Energy of $3.3 million, or $0.01 per diluted share of the Company's common stock, primarily due to higher other income due to a decrease in deferred compensation losses partially offset by higher interest expense.

A more detailed discussion regarding the financial performance of OG&E and the Natural Gas Midstream Operations can be found under "Results of Operations" below.

2014 Outlook

The Company's 2014 earnings guidance is between approximately $388 million and $411 million of net income, or $1.94 to $2.06 per average diluted share.

Key assumptions for 2014 include:

Consolidated OGE

- Approximately 200 million average diluted shares outstanding;
- An effective tax rate of approximately 30 percent; and
- A projected loss at the holding company of $2 million or $0.01 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings partially offset by tax deductions.

OG&E

The Company projects OG&E to earn approximately $292 million to $303 million, or $1.46 to $1.52 per average diluted share in 2014 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of approximately $1.355 billion to $1.345 billion based on sales growth of approximately 1.2 percent on a weather-adjusted basis;
- Approximately $115 million of gross margin is primarily attributed to regionally allocated transmission projects;
- Operating expenses of approximately $805 million to $815 million, with operation and maintenance expenses comprising 56 percent of the total;
- Interest expense of approximately $141 million which assumes a $4 million allowance for borrowed funds used during construction reduction to interest expense and $250 million of long-term debt issued in the first half of 2014;
- Other income of approximately $14 million including approximately $11 million of AEFUDC; and
- An effective tax rate of approximately 28 percent.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

OGE Enogex Holdings LLC

The Company projects equity earnings from its ownership interest in Enable to be between approximately $98 million to $110 million, or $0.49 to $0.55 per average diluted share. The outlook does not include any gains recognized each time Enable sells units representing the difference between book value and the unit sales price or the dilution associated with the issuance of limited partnership units from the planned Enable Midstream initial public offering.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2013, 2012 and 2011 and the Company's consolidated financial position at December 31, 2013 and 2012. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Year ended December 31 (In millions except per share data)	2013	2012	2011
Operating income	$553.5	$676.9	$646.7
Net income attributable to OGE Energy	$387.6	$355.0	$342.9
Basic average common shares outstanding	198.2	197.1	195.8
Diluted average common shares outstanding	199.4	198.1	198.5
Basic earnings per average common share attributable to OGE Energy common shareholders	$1.96	$1.80	$1.75
Diluted earnings per average common share attributable to OGE Energy common shareholders	$1.94	$1.79	$1.73
Dividends declared per common share	$0.8513	$0.7975	$0.7588

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income and equity in earnings of unconsolidated affiliates as reported in its Consolidated Statements of Income as those measures indicate the ongoing profitability of the Company excluding the cost of capital and income taxes.

Operating Results by Business Segment

Year ended December 31 (In millions)	2013	2012	2011
Operating Income (Loss)			
OG&E (Electric Utility)	$525.3	$489.4	$472.3
OGE Holdings (Natural Gas Midstream Operations) (A)	33.2	185.6	175.1
Other Operations (B)	(5.0)	1.9	(0.7)
Consolidated operating income	$553.5	$676.9	$646.7
Equity in Earnings of Unconsolidated Affiliate			
OGE Holdings (Natural Gas Midstream Operations) (A)	$101.9	$—	$—

(A) The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented.

(B) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

The following operating results analysis by business segment includes intercompany transactions that are eliminated in the Consolidated Financial Statements.

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OG&E (Electric Utility)			
Year ended December 31 (Dollars in millions)	2013	2012	2011
Operating revenues	$2,262.2	$2,141.2	$2,211.5
Cost of sales	965.9	879.1	1,013.5
Other operation and maintenance	438.8	446.3	436.0
Depreciation and amortization	248.4	248.7	216.1
Taxes other than income	83.8	77.7	73.6
Operating income	525.3	489.4	472.3
Allowance for equity funds used during construction	6.6	6.2	20.4
Other income	8.1	8.2	8.5
Other expense	4.6	4.3	8.4
Interest expense	129.3	124.6	111.6
Income tax expense	113.5	94.6	117.9
Net income	$292.6	$280.3	$263.3
Operating revenues by classification			
Residential	$901.4	$878.0	$943.5
Commercial	554.2	523.5	531.3
Industrial	220.6	206.8	216.0
Oilfield	176.4	163.4	165.1
Public authorities and street light	214.3	202.4	207.4
Sales for resale	59.4	54.9	65.3
System sales revenues	2,126.3	2,029.0	2,128.6
Off-system sales revenues	14.7	36.5	36.2
Other	121.2	75.7	46.7
Total operating revenues	$2,262.2	$2,141.2	$2,211.5
Reconciliation of gross margin to revenue:			
Operating revenues	2,262.2	2,141.2	2,211.5
Cost of sales	965.9	879.1	1,013.5
Gross Margin	1,296.3	1,262.1	1,198.0
MWH sales by classification (In millions)			
Residential	9.4	9.1	9.9
Commercial	7.1	7.0	6.9
Industrial	3.9	4.0	3.9
Oilfield	3.4	3.3	3.2
Public authorities and street light	3.2	3.3	3.2
Sales for resale	1.2	1.3	1.4
System sales	28.2	28.0	28.5
Off-system sales	0.4	1.4	1.0
Total sales	28.6	29.4	29.5
Number of customers	806,940	798,110	789,146
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	3.905	2.930	4.328
Coal	2.273	2.310	2.064
Total fuel	2.784	2.437	2.897
Total fuel and purchased power	3.178	2.806	3.215
Degree days (A)			
Heating - Actual	3,673	2,667	3,359
Heating - Normal	3,349	3,349	3,631
Cooling - Actual	2,106	2,561	2,776
Cooling - Normal	2,092	2,092	1,911

(A) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

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2013 compared to 2012. OG&E's operating income increased $35.9 million, or 7.3 percent, in 2013 as compared to 2012 primarily due to a higher gross margin, lower other operation and maintenance expense and lower depreciation and amortization expense partially offset by higher taxes other than income.

Gross Margin

Gross Margin is defined by OG&E as operating revenues less fuel, purchased power and transmission expenses. Gross margin is a non-GAAP financial measure because it excludes depreciation and amortization, and other operation and maintenance expenses. Expenses for fuel, purchased power and transmission expenses are recovered through fuel adjustment clauses and as a result changes in these expenses are offset in operating revenues with no impact on net income. OG&E believes gross margin provides a more meaningful basis for evaluating its operations across periods than operating revenues because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Board of Directors. OG&E's definition of gross margin may be different from similar terms used by other companies.

Operating revenues were $2,262.2 million in 2013 as compared to $2,141.2 million in 2012, an increase of $121.0 million, or 5.7 percent. Cost of sales were $965.9 million in 2013 as compared to $879.1 million in 2012, an increase of $86.8 million, or 9.9 percent. Gross margin was $1,296.3 million in 2013 as compared to $1,262.1 million in 2012, an increase of $34.2 million, or 2.7 percent. The below factors contributed to the change in gross margin:

	$ Change (In millions)
Wholesale transmission revenue (A)	$44.9
New customer growth	10.9
Other	1.8
Non-residential demand and related revenues	0.1
Quantity variance (primarily weather)	(6.4)
Price variance (B)	(17.1)
Change in gross margin	$34.2

(A) Increased primarily due to higher investments related to certain FERC approved transmission projects included in formula rates.

(B) Decreased primarily due to sales and customer mix.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $672.7 million in 2013 as compared to $642.4 million in 2012, an increase of $30.3 million, or 4.7 percent, primarily due to higher natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2013, OG&E's fuel mix was 53 percent coal, 40 percent natural gas and seven percent wind. In 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. Purchased power costs were $267.6 million in 2013 as compared to $223.0 million in 2012, an increase of $44.6 million, or 20.0 percent, primarily due to an increase in purchases in the energy imbalance service market and short-term power agreements. Transmission related charges were $25.6 million in 2013 as compared to $13.7 million in 2012, an increase of $11.9 million, or 86.9 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to its affiliate, Enable.

Operating Expenses

Other operation and maintenance expenses were $438.8 million in 2013 as compared to $446.3 million in 2012, a decrease of $7.5 million, or 1.7 percent. The below factors contributed to the change in other operations and maintenance expense:

	$ Change (In millions)
Employee benefits (A)	$(12.3)
Total salaries and wages (B)	(6.5)
Temporary labor	(2.3)
Contract professional services (primarily smart grid) (C)	(1.7)
Other	0.6
Other marketing and sales expense (primarily lower demand-side management initiatives) (C)	1.2
Administrative and assessment fees (primarily SPP Administration Fees)	2.2
Software expense (primarily smart grid) (C)	2.7
Capitalized labor	8.6
Change in other operation and maintenance expense	$(7.5)

(A) Decreased primarily due to lower recoverable amounts of pension expense and postretirement medical expense allowed in the August 2012 rate case, a decrease in medical expense, and a decrease in worker's compensation accruals.

(B) Decreased primarily due to lower salaries and wages as a result of lower headcount in 2013 and a decrease in incentive pay, partially offset by annual salary increases and an increase in overtime wages related to 2013 storms.

(C) Includes costs that are being recovered through a rider.

Depreciation and amortization expense was $248.4 million in 2013 as compared to $248.7 million in 2012, a decrease of $0.3 million, primarily due to the amortization of the deferred pension credits regulatory liability and a decrease in the amortization of the storm regulatory asset (see Note 1). These decreases in depreciation and amortization expense were partially offset by:

- increases in depreciation rates from the August 2012 rate case; and
- additional assets being placed in service throughout 2013 and 2012, including the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, the smart grid project which was completed in late 2012 and the Cleveland to Sooner transmission project which was fully in service in February 2013.

Taxes other than income was $83.8 million in 2013 as compared to $77.7 million in 2012, an increase of $6.1 million, or 7.9 percent, primarily due to higher ad valorem taxes.

Additional Information

Interest Expense. Interest expense was $129.3 million in 2013 as compared to $124.6 million in 2012, an increase of $4.7 million, or 3.8 percent, primarily due to a $6.4 million increase in interest on long term debt related to a $250 million debt issuance that occurred in May 2013, partially offset by a $2.0 million decrease in interest related to tax matters.

Income Tax Expense. Income tax expense was $113.5 million in 2013 as compared to $94.6 million in 2012, an increase of $18.9 million, or 20.0 percent primarily due to higher pre-tax income and a reserve related to a portion of the Oklahoma investment tax credits generated in years prior to 2013 but not yet utilized.

2012 compared to 2011. OG&E's operating income increased $17.1 million, or 3.6 percent, in 2012 as compared to 2011 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

Gross Margin

Operating revenues were $2,141.2 million in 2012 as compared to $2,211.5 million in 2011, a decrease of $70.3 million, or 3.2 percent. Fuel and purchased power was $879.1 million in 2012 as compared to $1,013.5 million in 2011, a decrease of

$134.4 million, or 13.3 percent. Gross margin was $1,262.1 million in 2012 as compared to $1,198.0 million in 2011, an increase of $64.1 million, or 5.4 percent. The below factors contributed to the change in gross margin:

	$ Change (In millions)
Price variance (A)	$54.1
Wholesale transmission revenue (B)	28.5
New customer growth	11.5
Non-residential demand and related revenues	4.9
Enogex transportation credit (C)	3.3
Arkansas rate increase	2.8
Oklahoma rate increase	2.7
Renewal of wholesale contract with customer	1.3
Other	0.3
Quantity variance (primarily weather)	(45.3)
Change in gross margin	$64.1

(A) Increased due to revenues from the recovery of investments, including the Crossroads wind farm and smart grid.

(B) Increased primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction.

(C) Increased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

Fuel expense was $642.4 million in 2012 as compared to $775.0 million in 2011, a decrease of $132.6 million, or 17.1 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. In 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. Purchased power costs were $223.0 million in 2012 as compared to $230.7 million in 2011, a decrease of $7.7 million, or 3.3 percent, primarily due to a decrease in cogeneration purchases and purchases in the energy imbalance service market due to milder weather partially offset by an increase in short-term power purchases. Transmission related charges were $13.7 million in 2012 as compared to $7.8 million in 2011, an increase of $5.9 million, or 75.6 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

Operating Expenses

Other operation and maintenance expenses were $446.3 million in 2012 as compared to $436.0 million in 2011, an increase of $10.3 million, or 2.4 percent. The below factors contributed to the change in other operations and maintenance expense:

	$ Change (In millions)
Salaries and wages (A)	$6.4
Contract professional and technical services (related to smart grid) (B)	4.2
Employee benefits (C)	3.4
Administration and assessment fees (primarily SPP and North American Electric Reliability Corporation)	3.4
Wind farm lease expense (primarily Crossroads) (B)	3.0
Injuries and damages	1.9
Ongoing maintenance at power plants (B)	1.9
Software (primarily smart grid) (B)	1.8
Other	0.2
Temporary labor	(1.7)
Uncollectibles	(2.4)
Vegetation management (primarily system hardening) (B)	(3.0)
Allocations from holding company (primarily lower contract professional services and lower payroll and benefits)	(3.1)
Capitalized labor	(5.7)
Change in other operation and maintenance expense	$10.3

(A) Increased primarily due to salary increases and an increase in incentive compensation expense partially offset by lower headcount in 2012 and a decrease in overtime expense.

(B) Includes costs that are being recovered through a rider.

(C) Increased primarily due to an increase in worker's compensation accruals, an increase in medical expense and an increase in postretirement medical expense partially offset by a decrease in pension expense.

Depreciation and amortization expense was $248.7 million in 2012 as compared to $216.1 million in 2011, an increase of $32.6 million, or 15.1 percent, primarily due to additional assets being placed in service throughout 2011 and 2012, including the Crossroads wind farm, which was fully in service in January 2012, the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, and the smart grid project which was completed in late 2012.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $6.2 million in 2012 as compared to $20.4 million in 2011, a decrease of $14.2 million, or 69.6 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

Other Income. Other income was $8.0 million in both 2012 and 2011. Factors affecting other income included an increased margin of $8.8 million recognized in the guaranteed flat bill program in 2012 as a result of milder weather offset by a decrease of $8.9 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

Other Expense. Other expense was $4.3 million in 2012 as compared to $8.4 million in 2011, a decrease of $4.1 million, or 48.8 percent primarily due to a decrease in charitable contributions.

Interest Expense. Interest expense was $124.6 million in 2012 as compared to $111.6 million in 2011, an increase of $13.0 million, or 11.6 percent, primarily due to a $6.9 million increase in interest expense related to lower allowance for borrowed funds used during construction costs for the Crossroads wind farm in 2011 and a $5.5 million increase in interest expense related to the issuance of long-term debt in May 2011.

Income Tax Expense. Income tax expense was $94.6 million in 2012 as compared to $117.9 million in 2011, a decrease of $23.3 million, or 19.8 percent. The decrease in income tax expense was primarily due to an increase in the amount of Federal

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renewable energy tax credits recognized associated with the Crossroads wind farm and lower pre-tax income in 2012 as compared to 2011.

OGE Holdings (Natural Gas Midstream Operations)

	December 31,		
(In millions)	2013	2012	2011
Operating revenues	$630.4	$1,608.6	$1,787.1
Cost of sales	489.0	1,120.1	1,346.6
Other operation and maintenance	60.9	172.9	162.5
Depreciation and amortization	36.8	108.8	77.6
Impairment of assets	—	0.4	6.3
Gain on insurance proceeds	—	(7.5)	(3.0)
Taxes other than income	10.5	28.3	22.0
Operating income (loss)	33.2	185.6	175.1
Equity in earnings of unconsolidated affiliates	101.9	—	—
Other income	10.2	1.0	3.9
Other expense	1.3	4.5	1.3
Interest expense	10.6	32.6	22.9
Income tax expense	26.9	45.7	51.7
Net income	106.5	103.8	103.1
Less: Net income attributable to noncontrolling interests	6.6	29.7	20.8
Net income attributable to OGE Holdings	$99.9	$74.1	$82.3

Effective May 1, 2013, the Company deconsolidated its previously held investment in Enogex Holdings and acquired a 28.5 percent equity interest in Enable which is being accounted for using the equity method of accounting. The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. All financial statement line items included in the table above (except equity in earnings of unconsolidated affiliates and income tax expense) reflect 2013 operations only through April 30, 2013 and are not comparable to the prior year due to the deconsolidation discussed above.

Year Ended December 31, 2013 as Compared to Year Ended December 31, 2012

(In millions)	Natural Gas Midstream Operations (Consolidated - Four Months Ended April 30, 2013)	OGE Holdings (Equity Method - Eight Months Ended December 31, 2013)	Total (Year Ended December 31, 2013)	Natural Gas Midstream Operations (Consolidated - Year Ended December 31, 2012)
Operating revenues	$630.4	$—	$630.4	$1,608.6
Cost of sales	489.0	—	489.0	1,120.1
Operating expenses	108.2	—	108.2	302.9
Operating income	33.2	—	33.2	185.6
Equity in earnings of unconsolidated affiliates	—	101.9	101.9	—
Income tax expense	9.4	17.5	26.9	45.7
Net income	15.5	84.4	99.9	74.1

OGE Holdings' results of operations for the four months ended April 2013 as compared to the same period of 2012 decreased due to lower NGLs prices, lower keep-whole processing spreads and the contract conversion of the Texas production volumes of one of Enogex LLC's five largest customers from keep-whole to fixed-fee, in addition to slightly higher other operation and maintenance expense and depreciation and amortization expense. These decreases were partially offset by increased gathering rates and volumes and inlet processing volumes associated with ongoing Enogex LLC expansion projects and the gas gathering assets acquired in August 2012.

Enable's results for the eight months ended December 31, 2013, were consistent with management's expectations in light of lower natural gas liquids prices and low seasonal and geographic price differentials. Enable continued to increase processing volumes through system expansions. Transportation throughput was impacted by system integrity projects and slightly lower demand. Gathering throughput was slightly lower, impacted by well connects, with lower throughput offset by the impact of minimum commitment features.

Income taxes in 2013 as compared to the same period in 2012 decreased due to a $16.4 million reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of Enable partially offset by deferred tax adjustments related to the Company's deconsolidation of Enogex Holdings and higher pre-tax income (net of noncontrolling interest).

Operating Data

	Four Months Ended April 30, 2013	Year Ended December 31, 2012	2011
Gathered volumes – TBtu/d	1.54	1.41	1.36
Incremental transportation volumes – TBtu/d (A)	0.63	0.67	0.58
Total throughput volumes – TBtu/d	2.17	2.08	1.94
Natural gas processed – TBtu/d	1.10	0.98	0.79
Condensate sold – million gallons	17	35	27
Average condensate sales price per gallon	$1.95	$1.95	$2.09
NGLs sold (keep-whole) – million gallons	(99	) 162	167
NGLs sold (purchased for resale) – million gallons	316	667	487
NGLs sold (percent-of-liquids) – million gallons	7	24	25
NGLs sold (percent-of-proceeds) – million gallons	5	14	6
Total NGLs sold – million gallons	229	867	685
Average NGLs sales price per gallon	$1.08	$0.89	$1.16
Average natural gas sales price per MMBtu	$3.48	$2.79	$4.08

(A) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

Enable Operating Data during the Eight Months Ended December 31, 2013

	Eight Months Ended December 31, 2013
Gathered volumes - TBtu/d (A)	3.5
Transportation volumes - TBtu/d	4.6
Natural gas processed - TBtu/d	1.5
NGLs sold - million gallons/d	2.6

(A) Excludes volumes billed under throughput agreements.

Enable Results of Operations during the Eight Months Ended December 31, 2013

	Eight Months Ended December 31, 2013
Operating revenues	$2,122.6
Cost of sales	1,240.5
Operating income	321.9

Net income	288.6

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Equity in earnings of unconsolidated affiliates includes OGE Energy's 28.5 percent share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex and its underlying equity in net assets of Enable, based on historical cost as of May 1, 2013. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates

	Eight Months Ended December 31, 2013
OGE's 28.5% share of Enable Net Income	$82.1
Amortization of basis difference	9.4
Elimination of Enogex Holdings fair value and other adjustments	10.4
OGE's Equity in earnings of unconsolidated affiliates	$101.9

2012 compared to 2011. Enogex's operating income increased $10.6 million, or 6.1 percent, in 2012 as compared to 2011. This increase was primarily due to:

- increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from as gathering assets acquired in November 2011 and August 2012;
- increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012;
- a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant as discussed below; and
- lower impairment of assets as discussed below.

These increases were partially offset by lower average natural gas and NGLs prices, higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income. In 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the operating income by $7.5 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during 2012.

Other operation and maintenance expense increased $10.4 million, or 6.4 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth; and
- increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases in other operation and maintenance expense were partially offset by:

- decreased costs for soil remediation projects; and
- lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012.

Depreciation and amortization expense increased $31.2 million, or 40.2 percent, primarily due to additional assets placed in service throughout 2011 and 2012, including the gas gathering assets acquired in November 2011 and August 2012.
Impairment of assets decreased $5.9 million, or 93.7 percent, primarily due to an impairment of $5.0 million related to a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to

the Atoka processing plant and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds increased $4.5 million related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant.

Taxes other than income increased $6.2 million, or 28.1 percent, primarily due to:

- sales tax of $3.5 million related to the acquisition of certain gas gathering assets in September 2012 as discussed in Note 3 of Notes to Consolidated Financial Statements; and
- increased ad valorem taxes resulting from additional assets placed in service throughout 2011 and 2012.

Other Income. Enogex's consolidated other income was $1.0 million during 2012 as compared to $3.9 million during 2011, a decrease of $2.9 million, or 74.4 percent, due to the recognition in April 2011 of a $2.3 million gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

Other Expense. Enogex's consolidated other expense was $4.5 million during 2012 as compared to $1.3 million during 2011, an increase of $3.2 million due to higher non-cash losses on retirements of equipment during 2012.

Interest Expense. Enogex's consolidated interest expense was $32.6 million during 2012 as compared to $22.9 million during 2011, an increase of $9.7 million, or 42.4 percent, primarily due to:

- a decrease in capitalized interest during 2012 due to the completion of several large capital projects as compared to 2011;
- higher borrowings partially offset by repayments under Enogex's revolving credit agreement during 2012 as compared to 2011; and
- borrowings under Enogex's term loan during 2012 with no comparable item during 2011.

Income Tax Expense. Enogex's consolidated income tax expense was $45.7 million during 2012 as compared to $51.7 million during 2011, a decrease of $6.0 million, or 11.6 percent, primarily due to lower pre-tax income (net of noncontrolling interest) during 2012 as compared to 2011.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $29.7 million during 2012 as compared to $20.8 million during 2011, an increase of $8.9 million or 42.8 percent, due to higher net income, the ArcLight group's increased ownership in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011 and an impairment recorded in August 2011 related to the Atoka processing plant.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million. OG&E is also required to maintain all of the railcars it has under the operating lease and has entered into an agreement with a non-affiliated company to furnish this maintenance.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E has a unilateral right to terminate this lease upon a 6-month notice effective April 2015 and April 2016.

Liquidity and Capital Resources

Working Capital

Working capital is defined as the amount by which current assets exceed current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

The balance of Accounts Receivable, Net and Accrued Unbilled Revenues was $250.5 million and $352.7 million at December 31, 2013 and 2012, respectively, a decrease of $102.2 million, or 29.0 percent, primarily due to the deconsolidation of Enogex Holdings on May 1, 2013 partially offset by higher transmission revenue, an increase in billings for reimbursable construction costs and an increase in billings to partners of jointly-owned power plants,

The balance of Accounts Payable was $251.0 million and $396.7 million at December 31, 2013 and 2012, respectively, a decrease of $145.7 million, or 36.7 percent, primarily due to the deconsolidation of Enogex Holdings on May 1, 2013 partly offset by increases primarily due to the timing of vendor payments and an increase in accruals.

Cash Flows

				2013 vs. 2012		2012 vs. 2011	
Year ended December 31 (In millions)	2013	2012	2011	$ Change	% Change	$ Change	% Change
Net cash provided from operating activities	$623.2	$1,046.1	$833.9	$(422.9)	(40.4)%	$212.2	25.4 %
Net cash used in investing activities	(957.0)	(1,192.6)	(1,395.8)	235.6	19.8 %	203.2	(14.6)%
Net cash provided from financing activities	338.8	143.7	564.2	195.1	*	(420.5)	(74.5)%

* Percentage is greater than 100 percent.

Operating Activities

The decrease of $422.9 million, or 40.4 percent, in net cash provided from operating activities in 2013 as compared to 2012 was primarily due to:

- fuel refunds at OG&E in 2013 as compared to higher fuel recoveries in 2012;
- the deconsolidation of Enogex Holdings on May 1, 2013.

The increase of $212.2 million, or 25.4 percent, in net cash provided from operating activities in 2012 as compared to 2011 was primarily due to:

- higher fuel recoveries at OG&E in 2012 as compared to 2011;
- an increase in cash received in 2012 from transmission revenue and the recovery of investments including the Crossroads wind farm and smart grid partially offset by milder weather in 2012; and
- an increase in gathered volumes and NGLs volumes at Enogex LLC during 2012 as compared to 2011 partially offset by lower natural gas and NGLs prices in 2012 as compared to 2011.

Investing Activities

The decrease of $235.6 million, or 19.8 percent, in net cash used in investing activities in 2013 as compared to 2012 is primarily a result of decreased capital expenditures related to the deconsolidation of Enogex Holdings on May 1, 2013 partially offset by increased capital expenditures at OG&E in 2013 related to various transmission projects.

The decrease of $203.2 million, or 14.6 percent, in net cash used in investing activities in 2012 as compared to 2011 primarily related to lower levels of capital expenditures in 2012 related to the Crossroads wind farm at OG&E and lower levels of capital expenditures related to gathering and processing expansion projects at Enogex LLC.

Financing Activities

The increase of $195.1 million in net cash provided from financing activities in 2013 as compared to 2012 was primarily due to:

- a decrease in repayments of lines of credit in 2013 as compared to 2012;
- payments on advances from unconsolidated affiliates due to the deconsolidation of Enogex Holdings on May 1, 2013; and
- and higher contributions from the Arclight group related to the closing of the transaction to form Enable.

These increases in net cash provided from financing activities were partially offset by a decrease in short-term debt borrowings during 2013 as compared to 2012.

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The decrease of $420.5 million in net cash provided from financing activities in 2012 as compared to 2011 was primarily due to:

- lower contributions from the ArcLight group during 2012 as compared to 2011;higher borrowings under Enogex LLC's revolving credit agreement during 2011; and
- repayments of Enogex's line of credit during 2012.

These increases in net cash provided from financing activities were partially offset by an increase in short-term debt borrowings during 2012 as compared to 2011.

Future Capital Requirements and Financing Activities

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2014 through 2018 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects. The Company believes that Enable has, or will have, access to adequate liquidity and, therefore, no contributions are expected to be necessary to fund the capital expenditures of Enable from the general partners. Accordingly, capital expenditures for Enable are not included in the table below.

(In millions)	2014	2015	2016	2017	2018
OG&E Base Transmission	$30	$30	$30	$30	$30
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	140	75	75	75	75
OG&E Other	15	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	360	295	295	295	295
OG&E Known and Committed Projects:					
Transmission Projects:					
Regionally Allocated Base Projects (A)	55	20	20	20	20
Balanced Portfolio 3E Projects (B)(C)	15	—	—	—	—
SPP Priority Projects (B)(C)	75	—	—	—	—
SPP Integrated Transmission Projects (B) (C)	15	25	30	25	10
Total Transmission Projects	160	45	50	45	30
Other Projects:					
Smart Grid Program	25	10	10	—	—
Environmental - low NOX burners	35	20	15	10	—
Environmental - activated carbon injection	5	10	5	—	—
Total Other Projects	65	40	30	10	—
Total OG&E Known and Committed Projects	225	85	80	55	30
Total OG&E (D)	585	380	375	350	325
OGE Energy	15	10	10	10	10
Total capital expenditures	$600	$390	$385	$360	$335

(A) Approximately 30% of revenue requirement allocated to SPP members other than OG&E.

(B) Approximately 85% of revenue requirement allocated to SPP members other than OG&E.

(C) Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Balance Portfolio 3E	96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the Oklahoma /Texas Stateline to a companion transmission line to its Tuco substation	$110	Mid-2014
Priority Project	99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the western Beaver County line to a companion transmission line to its Hitchland substation	$165	Mid-2014
Priority Project	77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border	$140	Late 2014
Integrated Transmission Project	47 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation	$45	Early 2018
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation; construction of the Mathewson substation on this transmission line	$180	Early 2021

(D) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling SO_2 emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO_2 emissions standards in the EPA's FIP could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit. On July 19, 2013, the U.S. Court of Appeals for the Tenth Circuit by a 2 to 1 vote denied the petition for review and affirmed the EPA's issuance of the FIP. On January 2, 2014, the Tenth Circuit confirmed that the stay of the FIP has remained in place and continues until the Tenth Circuit issues the mandate. A Petition for Certiorari was filed by the State of Oklahoma, the Industrial Consumers and OG&E with the United States Supreme Court on January 29, 2014. The mandate from the Tenth Circuit has been stayed until the Supreme Court acts on the petition. If the Supreme Court elects not to hear the case, OG&E will have approximately 55 months from the effective date of the lifting of the stay to achieve compliance with the FIP.

- Installation of control equipment (other than activated carbon injection) for compliance with MATS by a deadline of April 16, 2016, which includes a one-year extension which was granted by the Oklahoma Department of Environmental Quality. As noted above, OG&E is currently planning to utilize activated carbon injection for the removal of mercury at each of its five coal-fired units, the capital costs of which are estimated to be approximately $20 million over a three year period and are included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E continues to review whether additional controls such as dry sorbent injection are needed for compliance with MATS. Current capital costs for installing the necessary control equipment for dry sorbent injection are estimated to be approximately $45 million over a three year period, but due to the uncertainty as to whether or not dry sorbent injection is necessary, such costs are not included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Environmental Laws and Regulations" below.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets will be evaluated based upon their impact upon achieving the Company's financial objectives.

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2013. See the Company's Consolidated Statements of Capitalization and Note 15 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2014	2015-2016	2017-2018	After 2018	Total
Maturities of long-term debt (A)	$100.2	$110.4	$375.2	$1,819.9	$2,405.7
Operating lease obligations					
Railcars	3.8	30.4	—	—	34.2
Wind farm land leases	2.1	4.2	4.8	48.8	59.9
OGE Energy noncancellable operating lease	0.8	1.6	1.5	—	3.9
Total operating lease obligations	6.7	36.2	6.3	48.8	98.0
Other purchase obligations and commitments					
Cogeneration capacity and fixed operation and maintenance payments	85.1	164.6	156.6	235.2	641.5
Expected cogeneration energy payments	61.1	136.6	168.9	352.5	719.1
Minimum fuel purchase commitments	451.8	820.3	385.1	—	1,657.2
Expected wind purchase commitments	58.0	118.7	120.3	368.9	665.9
Long-term service agreement commitments	70.5	5.3	21.7	187.9	285.4
Total other purchase obligations and commitments	726.5	1,245.5	852.6	1,144.5	3,969.1
Total contractual obligations	833.4	1,392.1	1,234.1	3,013.2	6,472.8
Amounts recoverable through fuel adjustment clause (B)	(574.7)	(1,106.0)	(674.3)	(721.4)	(3,076.4)
Total contractual obligations, net	$258.7	$286.1	$559.8	$2,291.8	$3,396.4

(A) Maturities of the Company's long-term debt during the next five years consist of $100.2 million, $0.2 million, $110.2 million$125.1 million and $250.1 million in years 2014, 2015, 2016, 2017 and 2018, respectively.

(B) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's expected cogeneration energy payments, OG&E's minimum fuel purchase commitments and OG&E's expected wind purchase commitments.

OG&E also has 440 MWs of QF contracts to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

The actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of minimum fuel purchase commitments of OG&E noted above may increase capital requirements, such costs are recoverable through fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC.

Pension and Postretirement Benefit Plans

At December 31, 2013, 40.6 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in U.S Government securities, bonds, debentures and notes, a commingled fund and a common collective trust as presented in Note 13 of Notes to Consolidated Financial Statements. In 2013, asset returns on the Pension Plan were 12.5 percent due to the gains in fixed income and equity investments. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, increased. During both 2013 and 2012, OGE Energy made contributions to its Pension Plan of $35 million to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2014, OGE Energy expects to contribute up to $26 million to its Pension

Plan. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2013 and 2012. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 (In millions)	2013	2012	2013	2012	2013	2012
Benefit obligations	$(658.1)	$(747.1)	$(14.0)	$(14.5)	$(258.2)	$(301.0)
Fair value of plan assets	654.9	626.0	—	—	61.4	59.6
Funded status at end of year	$(3.2)	$(121.1)	$(14.0)	$(14.5)	$(196.8)	$(241.4)

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization’s net periodic pension cost. During 2013, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement. As a result, and based in part on the Company’s historical experience regarding eligible employees who elect to retire in the last quarter of a particular year, the Company recorded pension settlement charges of $22.4 million in the fourth quarter of 2013, of which $17.0 million related to OG&E’s Oklahoma jurisdiction and has been included in the pension tracker. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company’s total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

Common Stock Dividends

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The Company's financial objective includes increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends of approximately 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's December 2013 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.22500 per share from $0.20875 per share effective with the Company's first quarter 2014 dividend.

Security Ratings

	Moody’s Investors Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E Senior Notes	A1	A-	A+
OGE Energy Senior Notes	A3	BBB+	A-
OGE Energy Commercial Paper	P2	A2	F2

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

In conjunction with the closing of Enable on May 1, 2013, on May 2, 2013, Standard & Poor's Ratings Services upgraded the long-term senior unsecured rating of OGE Energy to BBB+ and OG&E to A-. All other security ratings from S&P remain unchanged.

On November 8, 2013, Moody's Investors Services placed the credit ratings of OGE Energy and OG&E on review for possible upgrade. On January 31, 2014, Moody's upgraded the long-term senior unsecured rating of OGE Energy to A3 and OG&E to A1 primarily due to their more favorable view of the relative credit supportiveness of the U.S. regulatory environment. All other security ratings from Moody's remain unchanged.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

2013 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $990.7 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $96.4 million resulting in total net capital requirements and contractual obligations of $1,087.1 million in 2013, of which $42.0 million was to comply with environmental regulations. This compares to net capital requirements of $1,351.8 million and net contractual obligations of $112.8 million totaling $1,464.6 million in 2012, of which $12.9 million was to comply with environmental regulations.

In 2013, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan, funding for growth opportunities at Enogex through the ArcLight group, distributions from Enogex Holdings and distributions from Enable. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Issuance of Long-Term Debt

On May 8, 2013, OG&E issued $250 million of 3.9% senior notes due May 1, 2043. The proceeds from the issuance were added to OG&E's general funds and were used to repay short-term debt, to fund capital expenditures, to pay general corporate expenses and for working capital purposes.

Potential Collateral Requirements

Derivative instruments are utilized in managing OG&E's commodity price exposures. On July 21, 2010, President Obama signed into law the Dodd-Frank Act. Among other things, the Dodd-Frank Act provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps and margin requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users such as OG&E from much of the clearing requirements. The regulations require that the decision on whether to use the end-user exception from mandatory clearing for derivative transactions be reviewed and approved by an "appropriate committee" of the Board of Directors. The scope of the margin requirements and their potential direct impact on OG&E remain unclear because final rules have not been issued. Further, even if OG&E qualifies for the end-user exception to clearing and margin requirements are not imposed on end-users, its derivative counterparties may be subject to new capital, margin and business conduct requirements as a result of the new regulations, which may increase OG&E's transaction costs or make it more difficult to enter into derivative transactions on favorable terms. OG&E's inability to enter into derivative transactions on favorable terms, or at all, could increase operating expenses and put OG&E at increased exposure to risks of adverse changes in commodities prices. The impact of the provisions of the Dodd-Frank Act on OG&E cannot be fully determined at this time due to uncertainty over forthcoming regulations and potential changes to the derivatives markets arising from new regulatory requirements.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The Company has revolving credit facilities totaling in the aggregate $1,150.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was $439.6 million and $430.9 million at December 31, 2013 and 2012, respectively. The weighted-average interest rate on short-term debt at December 31, 2013 was 0.30 percent. The average balance of short-term debt in 2013 was $485.0 million at a weighted-average interest rate of 0.34 percent. The maximum month-end balance of short-term debt in 2013 was $663.9 million. At December 31, 2013, the Company had $715.1 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2013 and ending December 31, 2014. At December 31, 2013, the Company had $6.8 million in cash and cash equivalents. See Note 12 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

In December 2011, the Company and OG&E entered into unsecured five-year revolving credit agreements to total in the aggregate $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year, subject to consent of a specified percentage of the lenders. Effective July 29, 2013, the Company and OG&E utilized one of these one-year extensions, and received consent from all of the lenders, to extend the maturity of their credit agreements to December 13, 2017.

Expected Issuance of Long-Term Debt

OG&E expects to issue up to $250 million of long-term debt during 2014, depending on market conditions, to fund capital expenditures, to repay short or long-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $10 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2014. See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable limited partnership agreement, during 2013 Enable made distributions of approximately $51.7 million to the Company.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) income taxes, contingency reserves, asset retirement obligations and assets and depreciable lives of property, plant and equipment. For the electric utility segment, the most significant judgment is also exercised in the existence of regulatory assets and liabilities and unbilled revenues. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of Notes to Consolidated Financial Statements.

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers a significant amount of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover a significant amount of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 13 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 1 percent	+/- $6.5 million
Discount rate	+/- 0.25 percent	+/- $18.3 million
Contributions	+/- $10 million	+/- $10 million

Assessing Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets or goodwill.

The Company assesses its long-lived assets (inclusive of definite-lived intangible assets prior to the deconsolidation of Enogex Holdings) for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 4 of Notes to Consolidated Financial Statements), related to the Atoka processing plant. The Company recorded no other material impairments in 2013, 2012 or 2011.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.
The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially

affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements.

Except as disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 74 years. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

Hedging Policies

From time to time, OG&E may engage in cash flow and fair value hedge transactions to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates. The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation.

Unbilled Revenues

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2013, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.3 million. At December 31, 2013 and 2012, Accrued Unbilled Revenues were $58.7 million and $57.4 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. At December 31, 2013, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.2 million. The allowance for uncollectible accounts receivable

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is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.9 million and $2.6 million at December 31, 2013 and 2012, respectively.

Accounting Pronouncements

See Note 2 of Notes to Consolidated Financial Statements for discussion of current accounting pronouncements that are applicable to the Company.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of the Company are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection relating to air quality, water quality, waste management, wildlife conservation and natural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate environmental issues that may be caused by its operations or that are attributable to former operators, requiring changes in operations and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

OG&E expects that environmental capital expenditures necessary to comply with the environmental laws and regulations discussed below will qualify as part of a regulatory plan to handle state and Federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2014 will be $72.6 million, of which $55.0 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2015 will be $49.6 million, of which $31.3 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and activated carbon injection and exclude certain other capital expenditures as discussed in footnote D to the capital expenditures table in "Future Capital Requirements and Financing Activities" above.

Air

Federal Clean Air Act Overview

OG&E's operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. OG&E likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners with overfire air (flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total capital cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be approximately $80 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at the four affected coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA issued a final rule in which it rejected portions of the Oklahoma SIP and issued a FIP in their place. While the EPA accepted Oklahoma's BART determination for NOX in the final rule, it rejected Oklahoma's SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. The EPA is instead requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would include capital costs to OG&E of more than $1.0 billion. OG&E and the state of Oklahoma filed an administrative stay request with the EPA on February 24, 2012. The EPA has not yet responded to this request. OG&E and other parties also filed a petition for review of the FIP in the U.S. Court of Appeals for the Tenth Circuit on February 24, 2012 and a stay request on April 4, 2012. On June 22, 2012, the U.S. Court of Appeals for the Tenth Circuit granted the stay request. On July 19, 2013, the U.S. Court of Appeals for the Tenth Circuit by a 2 to 1 vote denied the petition for review and affirmed the EPA's issuance of the FIP. On January 2, 2014, the Tenth Circuit confirmed that the stay of the FIP has remained in place and continues until the Tenth Circuit issues the mandate. A Petition for Certiorari was filed by the State of Oklahoma, the Industrial Consumers and OG&E with the United States Supreme Court on January 29, 2014. The mandate from the Tenth Circuit has been stayed until the Supreme Court acts on the petition. If the Supreme Court elects not to hear the case, OG&E will have approximately 55 months from the effective date of the lifting of the stay to achieve compliance with the FIP.

Cross-State Air Pollution Rule

As previously reported, on July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule would require 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule, which would make six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule was challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule, which includes the supplemental rule, pending a decision on the merits. By order dated August 21, 2012, the U.S. Court of Appeals vacated the Cross-State Air Pollution Rule and ordered the EPA to promulgate a replacement rule. On June 24, 2013, the U.S. Supreme Court agreed to review the decision by the U.S. Court of Appeals, with a decision expected during the first half of 2014. OG&E cannot predict the outcome of such challenges.

Hazardous Air Pollutants Emission Standards

On April 16, 2012, regulations governing emissions of certain hazardous air pollutants from electric generating units were published as the final MATS rule. This rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. Compliance with the MATS rule is required within three years after the effective date of the rule with the possibility of a one-year extension. OG&E requested and was granted a one-year extension by the Oklahoma Department of Environmental Quality resulting in a compliance date of April 16, 2016 for OG&E. To comply with this rule, OG&E is currently planning to utilize activated carbon injection for the removal of mercury at each of its five coal-fired units, the capital costs of which are estimated to be approximately $20 million over a three year period and are included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E continues to review whether additional controls such as dry sorbent injection are needed for compliance with MATS. Current capital costs for installing the necessary control equipment for dry sorbent injection are estimated to be approximately $45 million over a three year period, but due to the uncertainty as to whether or not dry sorbent injection is necessary, such costs are not included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E is evaluating the results of field testing to finalize its plans and cost estimates. The final MATS rule has been appealed by several parties. OG&E is not a party to the appeals and cannot predict the outcome of any such appeals.

Federal Clean Air Act New Source Review Litigation

As previously reported, in July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards.

In March 2013, the DOJ informed OG&E that it was prepared to initiate enforcement litigation concerning the matters identified in the notice of violation. OG&E subsequently met with EPA and DOJ representatives regarding the notice of violation and proposals for resolving the matter without litigation. On July 8, 2013, the United States, at the request of the EPA, filed a complaint for declaratory relief against OG&E in United States District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Federal Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. This complaint seeks to have OG&E submit a new assessment of whether the projects were likely to result in a significant emissions increase. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. OG&E expects to vigorously defend against these claims, but OG&E cannot predict the outcome of such litigation. On August 12, 2013, the Sierra Club filed a complaint against OG&E in the United States District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act.

If OG&E does not prevail in these proceedings and if a new assessment of the projects were to conclude that they caused a significant emissions increase, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.0 billion and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant. OG&E cannot predict at this time whether it will be legally required to incur any of these costs.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2013, no areas of Oklahoma had been designated as nonattainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS. The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

Acid Rain Program

The Federal Clean Air Act includes an Acid Rain Program. The goal of the Acid Rain Program is to achieve environmental and public health benefits through reductions in SO2 and NOX emissions, which are the primary causes of acid rain. To achieve this goal, the program employs both traditional and market-based approaches for reducing emissions.

The Acid Rain Program introduces an allowance trading system that uses the free market to reduce emissions. Under this system, affected utility units are allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO2 during or after a specified year. For each ton of SO2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold or banked.

During Phase II of the program (now in effect), the Federal Clean Air Act set a permanent ceiling (or cap) of 8.95 million total annual allowances allocated to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. Due to OG&E's earlier decision to burn low sulfur coal, these restrictions have had no significant financial impact.

The Acid Rain Program also focuses on one set of sources that emit NOX, coal-fired electric utility boilers. As with the SO2 emission reduction requirements, the NOX program was implemented in two phases, beginning in 1996 and 2000. The NOX program embodies many of the same principles of the SO2 trading program. However, it does not cap NOX emissions as the SO2 program does, nor does it utilize an allowance trading system.

Emission limitations for NOX focus on the emission rate to be achieved (expressed in pounds of NOX per MMBtu of heat input). In general, two options for compliance with the emission limitations are provided: compliance with an individual emission rate for a boiler; or averaging of emission rates over two or more units to meet an overall emission rate limitation.

Since becoming subject to the Acid Rain Program, OG&E has met all obligations and limitations requirements.

Climate Change and Greenhouse Gas Emissions

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain, but the EPA believes it has existing authority under the Clean Air Act to regulate greenhouse gas emissions from stationary sources. Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Oklahoma and Arkansas are not among them. If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on the Company's facilities, this could result in significant additional compliance costs that would affect the Company’s future financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

In 2009, the EPA adopted a comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E facilities. OG&E also reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program. OG&E has submitted the reports required by the applicable reporting rules.

Following from the Supreme Court's interpretation of the Clean Air Act's applicability to greenhouse gases in Massachusetts v. EPA, the EPA has proposed regulations for new power plants. In 2010, the EPA also issued a final rule that makes certain existing sources subject to permitting requirements for greenhouse gas emissions. This rule requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources that undergo construction or modification may have to install best available control technology to control greenhouse gas emissions. Although these rules currently do not have a material impact on the Company's existing facilities, they ultimately could result in significant changes to the Company's operations, significant capital expenditures by the Company

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and a significant increase in the Company's cost of conducting business. In October 2013, the U.S. Supreme Court granted certiorari to review EPA's greenhouse gas regulations, including the Tailoring Rule which limits the sources subject to greenhouse gas permitting requirements to the largest fossil-fueled power plants. It is conceivable that the Court could invalidate EPA's prevention of significant deterioration and Title V Tailoring Rule, but still leave power plants subject to anticipated new and existing source performance standards for greenhouse gas emissions described below.

In January 2014, the EPA issued new proposed New Source Performance Standards that specify permissible levels of greenhouse gas emissions from newly-constructed fossil fuel-fired electric generating units. The proposed New Source Performance Standards sets separate standards for natural gas combined cycle units and coal-fired generating units. As directed by President Obama's June 25, 2013, Climate Action Plan, the EPA also announced plans to establish, pursuant to Section 111(d) of the Clean Air Act, carbon dioxide emissions standards for existing fossil fuel fired electric generating units. EPA plans to publish the proposed standards for existing units by June 1, 2014, and finalize those guidelines by June 1, 2015. States must then submit their individual plans for reducing power plants' greenhouse gas emissions to EPA by June 30, 2016.

The Company is continuing to review and evaluate available options for reducing, avoiding, offsetting or sequestering its greenhouse gas emissions.

The Company also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory is in central Oklahoma and borders one of the nation's best wind resource areas. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. The SPP has begun to authorize the construction of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas Panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery limitations.

Endangered Species

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas become subject to protection, the Company’s operations and development projects, particularly transmission or wind projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures. The U.S. Fish and Wildlife Service announced a proposed rule to list the lesser prairie chicken as threatened on November 30, 2012. A final decision regarding listing is anticipated to be completed by March 30, 2014. Although the lesser prairie chicken and its habitat are located in potential development areas of the Company, the impact of a final decision to list this species as threatened cannot be determined at this time.

Waste

OG&E's operations generate wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 as well as comparable state laws which impose detailed requirements for the handling, storage, treatment and disposal of waste.

For OG&E, these laws impose strict requirements on waste generators regarding their treatment, storage and disposal of waste. OG&E routinely generates small quantities of hazardous waste throughout its system. These wastes are treated, stored and disposed at facilities that are permitted to manage them.

In June 2010, the EPA proposed new rules under Federal Resource Conservation and Recovery Act of 1976 that could make the management of coal ash more costly. The extent to which the EPA intends to regulate coal ash is uncertain. The EPA continues to consider numerous comments received on the proposal. On January 29, 2014, the EPA entered into a consent decree directing them, by December 19, 2014, to sign for publication in the Federal Register a notice taking final action on the EPA's proposed Subtitle D option for coal ash which set performance standards for waste management, to be administered by the states.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2013, the Company obtained refunds of $3.5 million from the recycling of scrap metal, salvaged transformers and used transformer oil. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E's operations are subject to the Federal Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. The Federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Existing cooling water intake structures are regulated under the Federal Clean Water Act to minimize their impact on the environment.
With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). Recently, the EPA announced that it will issue a final rule by April 17, 2014. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E utilizes various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E or Enogex.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 15 of Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Oversight Committee

Management monitors market risks using a risk committee structure.   The Company's Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all market risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. On a quarterly basis, the Risk Oversight Committee reports to the Audit Committee of the Company's Board of Directors on the Company's risk profile affecting anticipated financial results, including any significant risk issues.

The Company also has a Corporate Risk Management Department. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to market risk management are being followed.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

Year ended December 31 (Dollars in millions)	2014	2015	2016	2017	2018	Thereafter	Total	12/31/13 Fair Value
Fixed-rate debt (A)								
Principal amount	$100.2	$0.2	$110.2	$125.1	$250.1	$1,684.5	$2,270.3	$2,517.2
Weighted-average interest rate	5.00 %	2.95 %	5.15 %	6.50 %	6.35 %	6.03 %	6.00 %	
Variable-rate debt (B)								
Principal amount	$—	$—	$—	$—	$—	$135.4	$135.4	$135.4
Weighted-average interest rate	— %	— %	— %	— %	— %	0.13 %	0.13 %	

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $1.4 million annually.

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Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 (In millions except per share data)	2013	2012	2011
OPERATING REVENUES			
Electric Utility operating revenues	$2,259.7	$2,128.7	$2,211.5
Natural Gas Midstream Operations operating revenues (Note 1)	608.0	1,542.5	1,704.4
Total operating revenues	2,867.7	3,671.2	3,915.9
COST OF SALES			
Electric Utility Fuel and purchased power	950.0	831.4	966.0
Natural Gas Midstream Operations Cost of sales and fuel (Note 1)	478.9	1,087.3	1,311.9
Total cost of sales	1,428.9	1,918.7	2,277.9
OPERATING EXPENSES			
Other operation and maintenance	489.2	601.5	581.2
Depreciation and amortization	297.3	371.0	307.1
Impairment of assets	—	0.4	6.3
Gain on insurance proceeds	—	(7.5)	(3.0)
Taxes other than income	98.8	110.2	99.7
Total operating expenses	885.3	1,075.6	991.3
OPERATING INCOME	553.5	676.9	646.7
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates (Note 1)	101.9	—	—
Allowance for equity funds used during construction	6.6	6.2	20.4
Other income	31.8	17.6	19.8
Other expense	(22.2)	(16.5)	(21.7)
Net other income (expense)	118.1	7.3	18.5
INTEREST EXPENSE			
Interest on long-term debt	145.6	158.9	146.1
Allowance for borrowed funds used during construction	(3.4)	(3.5)	(10.4)
Interest on short-term debt and other interest charges	5.3	8.7	5.2
Interest expense	147.5	164.1	140.9
INCOME BEFORE TAXES	524.1	520.1	524.3
INCOME TAX EXPENSE	130.3	135.1	160.7
NET INCOME	393.8	385.0	363.6
Less: Net income attributable to noncontrolling interests	6.2	30.0	20.7
NET INCOME ATTRIBUTABLE TO OGE ENERGY	$387.6	$355.0	$342.9
BASIC AVERAGE COMMON SHARES OUTSTANDING	198.2	197.1	195.8
DILUTED AVERAGE COMMON SHARES OUTSTANDING	199.4	198.1	198.5
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$1.96	$1.80	$1.75
DILUTED EARNINGS PER AVERAGE COMMON SHARES ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$1.94	$1.79	$1.73
DIVIDENDS DECLARED PER COMMON SHARE	$0.8513	$0.7975	$0.7588

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 (In millions)	2013	2012	2011
Net income	$393.8	$385.0	$363.6
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $2.4, $1.7 and $1.4, respectively	3.7	3.0	2.5
Net gain (loss) arising during the period, net of tax of $7.8, ($5.6) and ($6.7), respectively	12.4	(10.2)	(13.5)
Amortization of prior service cost, net of tax of $0, $0.2 and $0.2, respectively	—	0.2	0.4
Settlement cost, net of tax of $1.9, $0 and $0, respectively	3.0	—	—
Postretirement Benefit Plans:			
Amortization of deferred net loss, net of tax of $1.3, ($1.1) and ($1.6), respectively	2.0	2.0	1.8
Net loss arising during the period, net of tax of $4.4, ($1.1) and ($3.1), respectively	6.9	(2.3)	(3.6)
Amortization of deferred net transition obligation, net of tax of $0, $0.1 and $0.1, respectively	—	0.1	0.2
Amortization of prior service cost, net of tax of $(1.1), ($1.0) and ($1.6), respectively	(1.8)	(1.8)	(1.8)
Prior service credit arising during the period, net of tax of $0, $0, and $9.5, respectively	—	—	10.8
Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of $0.4, ($1.6) and $12.6, respectively	0.6	(3.6)	27.6
Deferred commodity contracts hedging gains (losses), net of tax of $0, $0.1 and ($1.7), respectively	—	0.4	(4.8)
Amortization of deferred interest rate swap hedging losses, net of tax of $0.1, $0.2, and $0.2, respectively	0.3	0.2	0.3
Other comprehensive income (loss), net of tax	27.1	(12.0)	19.9
Comprehensive income (loss)	420.9	373.0	383.5
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	—	(0.5)	(3.2)
Less: Comprehensive income attributable to noncontrolling interests	6.3	27.0	24.2
Less: Deconsolidation of Enogex Holdings	6.1	—	—
Total comprehensive income attributable to OGE Energy	$408.5	$346.5	$362.5

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (In millions)	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$393.8	$385.0	$363.6
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	298.6	374.8	307.7
Impairment of assets	—	0.4	6.3
Deferred income taxes and investment tax credits, net	125.9	143.7	166.0
Equity in earnings of unconsolidated affiliates	(101.9)	—	—
Distributions from unconsolidated affiliates	51.7	—	—
Allowance for equity funds used during construction	(6.6)	(6.2)	(20.4)
(Gain) loss on disposition and abandonment of assets	(8.6)	4.2	(2.7)
Gain on insurance proceeds	—	(7.5)	(3.0)
Stock-based compensation	(3.5)	(2.6)	7.8
Regulatory assets	26.8	20.3	14.0
Regulatory liabilities	(32.5)	(14.8)	(1.9)
Other assets	1.3	(6.9)	(7.6)
Other liabilities	(7.0)	(14.3)	(37.4)
Change in certain current assets and liabilities			
Accounts receivable, net	(34.0)	27.1	(48.0)
Accrued unbilled revenues	(1.3)	1.9	(2.5)
Income taxes receivable	1.6	1.1	(3.6)
Fuel, materials and supplies inventories	5.1	13.7	54.2
Fuel clause under recoveries	(26.2)	1.8	(0.8)
Other current assets	(4.5)	(8.6)	(8.2)
Accounts payable	56.9	25.1	34.5
Accounts payable - unconsolidated affiliates	3.7	—	—
Fuel clause over recoveries	(108.8)	101.5	(22.2)
Other current liabilities	(7.3)	6.4	38.1
Net Cash Provided from Operating Activities	623.2	1,046.1	833.9
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	(990.6)	(1,150.6)	(1,270.4)
Investment in unconsolidated affiliates	(2.7)	—	—
Acquisition of gathering assets	—	(78.6)	(200.4)
Proceeds from insurance	—	7.6	7.4
Reimbursement of capital expenditures	—	27.5	49.6
Proceeds from sale of assets	36.3	1.5	18.0
Net Cash Used in Investing Activities	(957.0)	(1,192.6)	(1,395.8)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	247.4	250.0	246.3
Changes in advances with unconsolidated affiliates	129.6	—	—
Contributions from noncontrolling interest partners	107.0	46.2	216.4
Issuance of common stock	14.2	14.3	14.8
Increase in short-term debt	8.7	153.8	132.1
Repayment of line of credit	—	(150.0)	(25.0)
Proceeds from line of credit	—	—	150.0
Purchase of treasury stock	—	(3.4)	(6.2)
Payment of long-term debt	(0.1)	(0.1)	—

Distributions to noncontrolling interest partners	(2.5)	(12.6)	(17.4)
Dividends paid on common stock	(165.5)	(154.5)	(146.8)
Net Cash Provided from Financing Activities	338.8	143.7	564.2
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5.0	(2.8)	2.3
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1.8	4.6	2.3
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$6.8	$1.8	$4.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 (In millions)	2013	2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$6.8	$1.8
Accounts receivable, less reserve of $1.9 and $2.6, respectively	179.4	295.3
Accounts receivable - unconsolidated affiliates	12.4	—
Accrued unbilled revenues	58.7	57.4
Income taxes receivable	5.6	7.2
Fuel inventories	74.4	93.3
Materials and supplies, at average cost	80.7	80.9
Deferred income taxes	215.8	187.7
Fuel clause under recoveries	26.2	—
Assets held for sale	—	25.5
Other	34.6	45.1
Total current assets	694.6	794.2
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	1,298.8	—
Other	61.0	52.2
Total other property and investments	1,359.8	52.2
PROPERTY, PLANT AND EQUIPMENT		
In service	9,183.1	11,504.4
Construction work in progress	468.5	387.5
Total property, plant and equipment	9,651.6	11,891.9
Less accumulated depreciation	2,978.8	3,547.1
Net property, plant and equipment	6,672.8	8,344.8
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	379.1	510.6
Intangible assets, net	—	127.4
Goodwill	—	39.4
Other	28.4	53.6
Total deferred charges and other assets	407.5	731.0
TOTAL ASSETS	$9,134.7	$9,922.2

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 (In millions)	2013	2012
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$439.6	$430.9
Accounts payable	251.0	396.7
Dividends payable	44.7	41.2
Customer deposits	70.9	70.3
Accrued taxes	39.9	48.1
Accrued interest	43.4	55.0
Accrued compensation	56.9	55.2
Long-term debt due within one year	100.0	—
Fuel clause over recoveries	0.4	109.2
Other	47.0	69.8
Total current liabilities	1,093.8	1,276.4
LONG-TERM DEBT	2,300.1	2,848.6
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	241.5	399.8
Deferred income taxes	2,125.3	1,948.8
Deferred investment tax credits	1.9	3.9
Regulatory liabilities	234.2	245.1
Deferred revenues	0.4	37.7
Other	100.4	89.5
Total deferred credits and other liabilities	2,703.7	2,724.8
Total liabilities	6,097.6	6,849.8
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	1,073.6	1,047.4
Retained earnings	1,991.7	1,772.4
Accumulated other comprehensive loss, net of tax	(28.2)	(49.1)
Treasury stock, at cost	—	(3.5)
Total OGE Energy stockholders' equity	3,037.1	2,767.2
Noncontrolling interests	—	305.2
Total stockholders' equity	3,037.1	3,072.4
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$9,134.7	$9,922.2

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 (In millions)		2013	2012
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 198.5 and 197.5 shares, respectively		$2.0	$1.0
Premium on common stock		1,071.6	1,046.4
Retained earnings		1,991.7	1,772.4
Accumulated other comprehensive loss, net of tax		(28.2)	(49.1)
Treasury stock, at cost, 0.1 and 0.1 shares, respectively		—	(3.5)
Total OGE Energy stockholders' equity		3,037.1	2,767.2
Noncontrolling interest		—	305.2
Total stockholders' equity		3,037.1	3,072.4
LONG-TERM DEBT			
SERIES	DUE DATE		
Senior Notes - OGE Energy			
5.00%	Senior Notes, Series Due November 15, 2014	100.0	100.0
Unamortized discount		(0.1)	(0.1)
Senior Notes - OG&E			
5.15%	Senior Notes, Series Due January 15, 2016	110.0	110.0
6.50%	Senior Notes, Series Due July 15, 2017	125.0	125.0
6.35%	Senior Notes, Series Due September 1, 2018	250.0	250.0
8.25%	Senior Notes, Series Due January 15, 2019	250.0	250.0
6.65%	Senior Notes, Series Due July 15, 2027	125.0	125.0
6.50%	Senior Notes, Series Due April 15, 2028	100.0	100.0
6.50%	Senior Notes, Series Due August 1, 2034	140.0	140.0
5.75%	Senior Notes, Series Due January 15, 2036	110.0	110.0
6.45%	Senior Notes, Series Due February 1, 2038	200.0	200.0
5.85%	Senior Notes, Series Due June 1, 2040	250.0	250.0
5.25%	Senior Notes, Series Due May 15, 2041	250.0	250.0
3.90%	Senior Notes, Series Due May 1, 2043	250.0	—
3.70%	Tinker Debt, Due August 31, 2062	10.3	10.7
Other Bonds - OG&E			
0.18% - 0.34%	Garfield Industrial Authority, January 1, 2025	47.0	47.0
0.10% - 0.39%	Muskogee Industrial Authority, January 1, 2025	32.4	32.4
0.10% - 0.30%	Muskogee Industrial Authority, June 1, 2027	56.0	56.0
Unamortized discount		(5.5)	(5.8)
Enogex LLC			
6.875%	Senior Notes, Series Due July 15, 2014	N/A	200.0
1.72%	Enogex LLC Term Loan Agreement, Due August 2, 2015	N/A	250.0
6.25%	Senior Notes, Series Due March 15, 2020	N/A	250.0
Unamortized discount		N/A	(1.6)
Total long-term debt		2,400.1	2,848.6
Less long-term debt due within one year		(100.0)	—
Total long-term debt (excluding debt due within one year)		2,300.1	2,848.6
Total Capitalization		$5,437.2	$5,921.0

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Treasury Stock	Total
Balance at December 31, 2010	$1.0	$968.2	$1,380.6	$(60.2)	$110.4	$—	$2,400.0
Net income	—	—	342.9	—	20.7	—	363.6
Other comprehensive income (loss), net of tax	—	—	—	19.6	0.3	—	19.9
Dividends declared on common stock	—	—	(148.7)	—	—	—	(148.7)
Issuance of common stock	—	14.8	—	—	—	—	14.8
Stock-based compensation and other	—	5.8	—	—	—	—	5.8
Contributions from noncontrolling interest partners	—	74.4	—	—	142.0	—	216.4
Distributions to noncontrolling interest partners	—	—	—	—	(17.4)	—	(17.4)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(28.9)	—	—	—	—	(28.9)
Purchase of treasury stock	—	—	—	—	—	(6.2)	(6.2)
Balance at December 31, 2011	$1.0	$1,034.3	$1,574.8	$(40.6)	$256.0	$(6.2)	$2,819.3
Net income	—	—	355.0	—	30.0	—	385.0
Other comprehensive income (loss), net of tax	—	—	—	(8.5)	(3.5)	—	(12.0)
Dividends declared on common stock	—	—	(157.4)	—	—	—	(157.4)
Issuance of common stock	—	14.3	—	—	—	—	14.3
Stock-based compensation and other	—	(8.7)	—	—	(0.2)	6.1	(2.8)
Contributions from noncontrolling interest partners	—	10.7	—	—	35.5	—	46.2
Distributions to noncontrolling interest partners	—	—	—	—	(12.6)	—	(12.6)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(4.2)	—	—	—	—	(4.2)
Purchase of treasury stock	—	—	—	—	—	(3.4)	(3.4)
Balance at December 31, 2012	$1.0	$1,046.4	$1,772.4	$(49.1)	$305.2	$(3.5)	$3,072.4
Net income	—	—	387.6	—	6.2	—	393.8
Other comprehensive income (loss), net of tax	—	—	—	27.0	0.1	—	27.1
Dividends declared on common stock	—	—	(168.8)	—	—	—	(168.8)
Issuance of common stock	—	14.2	—	—	—	—	14.2
Stock-based compensation and other	—	(1.8)	—	—	(0.8)	3.5	0.9
	—	22.5	—	—	84.5	—	107.0

Contributions from noncontrolling interest partners							
Distributions to noncontrolling interest partners	—	—	—	—	(2.5)	—	(2.5)
Deconsolidation of Enogex Holdings	—	—	0.5	(6.1)	(392.7)	—	(398.3)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(8.7)	—	—	—	—	(8.7)
2-for-1 forward stock split	1.0	(1.0)	—	—	—	—	—
Balance at December 31, 2013	$2.0	$1,071.6	$1,991.7	$(28.2)	$—	$—	$3,037.1

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. For a discussion of the change in the Company's business segments due to the formation of Enable, see Note 14. For periods prior to May 1, 2013, the Company consolidated Enogex Holdings in its Condensed Consolidated Financial Statements. All significant intercompany transactions have been eliminated in consolidation.

Effective May 1, 2013, OGE Energy, the ArcLight group and CenterPoint Energy, Inc., formed Enable Midstream Partners, LP to own and operate the midstream businesses of OGE Energy and CenterPoint. In the formation transaction, OGE Energy and ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy began accounting for its interest in Enable using the equity method of accounting. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable. OGE Energy also owns a 60 percent interest in any incentive distribution rights in Enable. Incentive distribution rights are expected to entitle the holder to increasing percentages, up to a maximum of 50 percent, of the cash distributed by Enable in excess of the target quarterly distributions to be set in connection with Enable's initial public offering. On November 26, 2013, Enable filed a registration statement on Form S-1 related to the proposed initial public offering of limited partnership interests that will have the effect of making Enable a publicly traded master limited partnership.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment consists of the Company's investment in Enable. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

As discussed below, the Company completed a 2-for-1 stock split of the Company's common stock effective July 1, 2013. All share and per share amounts within this Form 10-K reflect the effects of the stock split.

OGE Energy charges operating costs to its subsidiaries and unconsolidated affiliate based on several factors. Operating costs directly related to specific subsidiaries or unconsolidated affiliate are assigned to those subsidiaries or unconsolidated affiliate. Where more than one subsidiary or unconsolidated affiliate benefits from certain expenditures, the costs are shared between those subsidiaries and unconsolidated affiliate receiving the benefits. Operating costs incurred for the benefit of all subsidiaries and unconsolidated affiliate are allocated among the subsidiaries and unconsolidated affiliate, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

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Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2013 and 2012 and the results of its operations and cash flows for the years ended December 31, 2013, 2012 and 2011, have been included and are of a normal recurring nature except as otherwise disclosed.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

December 31 (In millions)	2013	2012
Regulatory Assets		
Current		
Fuel clause under recoveries	$26.2	$—
Oklahoma demand program rider under recovery (A)	10.6	9.2
Crossroads wind farm rider under recovery (A)	4.7	14.9
Other (A)	7.3	2.9
Total Current Regulatory Assets	$48.8	$27.0
Non-Current		
Benefit obligations regulatory asset	$227.4	$370.6
Income taxes recoverable from customers, net	56.5	54.7
Smart Grid	44.2	42.8
Deferred storm expenses	21.6	12.7
Unamortized loss on reacquired debt	11.8	13.0
Pension tracker	1.4	—
Other	16.2	16.8
Total Non-Current Regulatory Assets	$379.1	$510.6
Regulatory Liabilities		
Current		
Smart Grid rider over recovery (B)	$16.7	$24.1
Fuel clause over recoveries	0.4	109.2
Other (B)	3.1	7.8
Total Current Regulatory Liabilities	$20.2	$141.1
Non-Current		
Accrued removal obligations, net	$227.7	$218.2
Deferred pension credits	6.5	17.7

Pension tracker	—	9.2
Total Non-Current Regulatory Liabilities	$234.2	$245.1

(A) Included in Other Current Assets on the Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Consolidated Balance Sheets.

OG&E recovers a return on the capital expenditures along with operation and maintenance expense and depreciation expense related to the Crossroads wind farm through riders established by the OCC and APSC. OG&E began recovery in the fourth quarter of 2011 in Oklahoma and June of 2013 in Arkansas, and believes the rider will continue until new rates are implemented in OG&E's next general rate case in each jurisdiction.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in December 2012, which allows for the recovery of demand program costs, lost revenues associated with certain achieved energy, demand savings and performance based incentives and the recovery of costs associated with research and development investments through December 2015.

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation. These expenses are recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to Accumulated other comprehensive income.

The following table is a summary of the components of the benefit obligations regulatory asset at:

December 31 (In millions)	2013	2012
Pension Plan and Restoration of Retirement Income Plan		
Net loss	$178.4	$278.6
Prior service cost	2.5	4.5
Postretirement Benefit Plans		
Net loss	79.9	134.6
Prior service cost	(33.4)	(47.1)
Total	$227.4	$370.6

The following amounts in the benefit obligations regulatory asset at December 31, 2013 are expected to be recognized as components of net periodic benefit cost in 2014:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	$11.4
Prior service cost	2.0
Postretirement Benefit Plans	
Net loss	11.0
Prior service cost	(13.7)
Total	$10.7

Income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and liabilities and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The income tax related regulatory assets and liabilities are netted in Income taxes recoverable from customers, net in the regulatory assets and liabilities table above.

OG&E recovers the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports and stranded costs associated

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with OG&E's existing meters. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were capped at $366.4 million (inclusive of the U.S. Department of Energy grant award of $130.0 million) subject to an offset for any recovery of those costs from Arkansas customers. These amounts are currently being recovered through a rider which will remain in effect until the smart grid project costs are included in base rates in OG&E's next general rate case. Costs not included in the rider are the incremental costs for web portal access, education and home energy reports, which are capped at $6.9 million, and the stranded costs associated with OG&E's existing meters, which have been replaced by smart meters, which were accumulated during the smart grid deployment and have been included in the Smart Grid asset in the table above. These costs are expected to be recovered in base rates in OG&E's next general rate case.

OG&E defers annual Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and expenses any Oklahoma storm-related operation and maintenance expenses up to $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2017.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are recorded in interest expenses and are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is not included in OG&E's rate base and does not otherwise earn a rate of return.

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker in the regulatory assets and liabilities table above.

In September 2011, OG&E was allowed to include postretirement medical expenses in its pension tracker. In August 2012, OG&E was allowed to recover pension and postretirement medical expenses over a two-year period ending July 2014 which is included in Deferred pension credits in the regulatory assets and liabilities table above.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), income taxes, contingency reserves, asset retirement obligations and assets and depreciable lives of property, plant and equipment. For the electric utility segment, the most significant judgment is also exercised in the existence of regulatory assets and liabilities and unbilled revenues.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. The allowance for uncollectible accounts receivable was $1.9 million and $2.6 million at December 31, 2013 and 2012, respectively.

For OG&E, new business customers are required to provide a security deposit in the form of cash, bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers, whose outside credit scores indicate an elevated risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

Fuel Inventories

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $74.4 million and $76.8 million at December 31, 2013 and 2012, respectively.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by OG&E differ from the amounts scheduled to be delivered or received. OG&E values all imbalances at an average of current market indices applicable to OG&E's operations, not to exceed net realizable value.

Property, Plant and Equipment

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

December 31, 2013 (In millions)	Percentage Ownership	Total Property, Plant and	Accumulated Depreciation	Net Property, Plant and

			Equipment		Equipment
McClain Plant (A)	77	%	$180.8	$62.1	$118.7
Redbud Plant (A)(B)	51	%	$498.9	$89.7	$409.2

(A) Construction work in progress was $0.1 million and $39.5 million for the McClain and Redbud Plants, respectively.

(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $28.8 million.

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December 31, 2012 (In millions)	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	77 %	$182.1	$56.3	$125.8
Redbud Plant (A)(B)	51 %	$458.5	$69.5	$389.0

(A) Construction work in progress was $0.1 million and $0.3 million for the McClain and Redbud Plants, respectively.

(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

December 31, 2013 (In millions)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$152.4	$114.2	$38.2
OGE Energy property, plant and equipment	152.4	114.2	38.2
OG&E			
Distribution assets	3,403.8	1,028.2	2,375.6
Electric generation assets (A)	3,551.0	1,306.1	2,244.9
Transmission assets (B)	2,163.7	385.0	1,778.7
Intangible plant	50.5	27.1	23.4
Other property and equipment	330.2	118.2	212.0
OG&E property, plant and equipment	9,499.2	2,864.6	6,634.6
Total property, plant and equipment	$9,651.6	$2,978.8	$6,672.8

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $28.8 million.

(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.3 million.

December 31, 2012 (In millions)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$142.1	$103.2	$38.9
OGE Energy property, plant and equipment	142.1	103.2	38.9
OG&E			
Distribution assets	3,222.7	969.6	2,253.1
Electric generation assets (A)	3,446.6	1,242.4	2,204.2
Transmission assets (B)	1,712.6	359.8	1,352.8
Intangible plant	50.2	25.0	25.2
Other property and equipment	317.6	108.8	208.8
OG&E property, plant and equipment	8,749.7	2,705.6	6,044.1
Enogex			
Natural gas transportation and storage assets	988.6	292.7	695.9
Natural gas gathering and processing assets	2,011.5	445.6	1,565.9
Enogex property, plant and equipment	3,000.1	738.3	2,261.8
Total property, plant and equipment	$11,891.9	$3,547.1	$8,344.8

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.

(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.3 million.

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The following table summarizes the Company's unamortized computer software costs.

December 31 (In millions)	2013	2012
OGE Energy (holding company)	$7.2	$11.6
OG&E	16.8	17.6
Enogex	—	3.9
Total	$24.0	$33.1

The following table summarizes the Company's amortization expense for computer software costs.

Year ended December 31 (In millions)	2013	2012	2011
OGE Energy (holding company)	$6.4	$6.8	$6.4
OG&E	4.0	4.2	1.8
Enogex	0.8	3.1	1.0
Total	$11.2	$14.1	$9.2

Intangible Assets

As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets.

OGE Holdings

The following table below summarizes OGE Holdings' intangible assets and related accumulated amortization at: December 31, 2012.

(In millions)	Total Intangible Assets	Accumulated Amortization	Net Intangible Assets
Customer Contract / Acreage Dedication	$141.9	$14.5	$127.4

In 2013, 2012 and 2011, amortization expense for intangible assets was $1.9 million, $9.6 million and $2.1 million, respectively, including amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included as a reduction in revenue for financial reporting purposes.

Depreciation and Amortization

The provision for depreciation, which was 2.8 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2013 and 2012, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2014, the provision for depreciation is projected to be 2.8 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2013, 93.5 percent will be amortized over 9 years with 6.5 percent of the remaining amortizable intangible plant balance at December 31, 2013 being amortized over 26 years.. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $3.3 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

Investment in Unconsolidated Affiliate

OGE Energy's investment in Enable is considered to be a variable interest entity because the owners of the equity at risk in this entity have disproportionate voting rights in relation to their obligations to absorb the entity's expected losses or to receive its expected residual returns. However, OGE Energy is not considered the primary beneficiary of

Enable since it does not have the power to direct the activities of Enable that are considered most significant to the economic performance of Enable. As discussed above, OGE Energy accounts for the investment in Enable using the equity method of accounting. Under the equity method, the investment will be adjusted each period for contributions made, distributions received and the Company's share of the investee's comprehensive income. OGE Energy's maximum exposure to loss related to Enable is limited to OGE Energy's

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equity investment in Enable as presented on the Company's Consolidated Balance Sheet at December 31, 2013. The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

The Company considers distributions received from its unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment which are classified as operating activities in the Consolidated Statements of Cash Flows. The Company considers distributions received from its unconsolidated affiliates in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment which are classified as investing activities in the Consolidated Statements of Cash Flows.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2013 and 2012.

(In millions)	2013	2012
Balance at January 1	$54.0	$24.8
Liabilities settled (A)	(0.4)	0.4
Accretion expense	2.3	1.9
Revisions in estimated cash flows (B)	(0.7)	26.9
Balance at December 31	$55.2	$54.0

(A) As a result of the formation of Enable on May 1, 2013, the Company has no obligations at December 31, 2013 under OGE Holdings' asset retirement obligations previously disclosed in the Company's 2012 10-K.

(B) Due to changes to OG&E's asset retirement obligations related to its wind farms as a result of changes in the assumption related to the timing of removal used in the valuation of the asset retirement obligations.

Assessing Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets or goodwill.

The Company assesses its long-lived assets (inclusive of definite-lived intangible assets prior to the deconsolidation of Enogex Holdings) for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 4), related to the Atoka processing plant. The Company recorded no other material impairments in 2013, 2012 or 2011.

Allowance for Funds Used During Construction

For OG&E, allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as an increase to net other income and a reduction to interest expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.33 percent, 8.93 percent and 8.71 percent for the years ended December 31, 2013, 2012 and 2011, respectively. The decrease in the allowance for funds used during construction rates in 2013 was primarily due to two factors. First, a decrease in the common equity cost rate caused the equity portion of allowance for equity funds used during construction to decrease. Second, an increase in the average daily balance of short term debt allowed the fixed commercial paper

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fees to be lower per dollar of short term debt, resulting in a lower short term debt rate, which caused the debt portion of allowance for funds used during construction to decrease.

Collection of Sales Tax

In the normal course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability for sales taxes when it bills its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

General

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

OG&E participates in the SPP energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' MWH entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is an obligation, the participant is charged with a spot-market purchase from the SPP at the respective market price for that hour. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Sales in its Consolidated Financial Statements.

Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to its affiliate, Enable.

Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken. OGE employees can carryover no more than 80 hours to be used in future years.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes changes in the components of accumulated other comprehensive loss attributable to OGE Energy during 2013. All amounts below are presented net of tax and noncontrolling interest.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans					
(In millions)	Net loss	Prior service cost	Net loss	Prior service cost	Deferred commodity contracts hedging gains	Deferred interest rate swap hedging losses	Less: Noncontrolling interest	Total
Balance at December 31, 2012	$(49.3)	$0.1	$(15.7)	$7.2	$0.1	$(0.5)	$(9.0)	$(49.1)
Other comprehensive income before reclassifications	12.4	—	6.9	—	—	—	—	19.3
Amounts reclassified from accumulated other comprehensive income (loss) (A)	6.7	—	2.0	(1.8)	0.6	0.3	0.1	7.7
Deconsolidation of Enogex Holdings	2.8	—	1.0	(0.3)	(0.7)	—	8.9	(6.1)
Net current period other comprehensive income (loss)	21.9	—	9.9	(2.1)	(0.1)	0.3	9.0	20.9
Balance at December 31, 2013	$(27.4)	$0.1	$(5.8)	$5.1	$—	$(0.2)	$—	$(28.2)

(A) Includes $3.0 million of pension settlement charges.

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The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the year ended December 31, 2013.

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss	Affected Line Item in the Statement Where Net Income is Presented
(In millions)	Year Ended December 31, 2013	
Gains (losses) on cash flow hedges		
Commodity contracts	$(1.0)	Cost of sales
Interest rate swap	(0.4)	Interest expense
	(1.4)	Total before tax
	(0.5)	Tax benefit
	$(0.9)	Net of tax
Amortization of defined benefit pension items		
Actuarial gains (losses)	$(6.1)	(A)
Settlement cost	(4.9)	(A)
	(11.0)	Total before tax
	(4.3)	Tax benefit
	(6.7)	Net of tax
	(0.1)	Noncontrolling interest
	$(6.6)	Net of tax and noncontrolling interest
Amortization of postretirement benefit plan items		
Actuarial gains (losses)	$(3.3)	(A)
Prior service cost	2.9	(A)
	(0.4)	Total before tax
	(0.2)	Tax benefit
	$(0.2)	Net of tax
Total reclassifications for the period	$(7.7)	Net of tax and noncontrolling interest

(A) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost (see Note 13 for additional information).

The amounts in accumulated other comprehensive loss at December 31, 2013 that are expected to be recognized into earnings in 2014 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	$(1.7)
Prior service cost	(0.1)
Postretirement Benefit Plans	
Net loss	(0.8)
Prior service cost	1.8
Deferred commodity contracts hedging gains	—
Deferred interest rate swap hedging losses	(0.2)
Total, net of tax	$(1.0)

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Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E has been designated as one of several potentially responsible parties, the amount accrued represents OG&E's estimated share of the cost. The Company had $6.2 million and $5.8 million in accrued environmental liabilities at December 31, 2013 and 2012, respectively, which are included in the summary of asset retirement obligations above.

Forward Stock Split

On May 16, 2013, the Company's Board of Directors approved a 2-for-1 forward stock split of the Company's common stock, effective July 1, 2013, which entitled each shareholder of record to receive two shares for every one share of Company stock owned by the shareholder. In connection with the stock split, an amendment to the Company's Articles of Incorporation was approved on May 16, 2013 which increased the number of authorized shares of common stock from 225 million to 450 million. All share and per share amounts presented within this Form 10-K reflect the effects of the stock split.

Reclassifications

As discussed in Note 14, the former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. Effective May 1, 2013, the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable.

2. Accounting Pronouncements

In July 2013, the Emerging Issues Task Force issued "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward or Tax Credit Carryforward Exists." The new standard requires entities to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the statement of financial position as a reduction to a deferred tax asset for a net operating loss carryforward or a tax credit carryforward, except as follows: to the extent that a net operating loss carryforward or tax credit carryforward at the reporting date is not available under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, the unrecognized tax benefit would be presented in the statement of financial position as a liability. The new standard is applicable for all entities that have unrecognized tax benefits when a net operating loss carryforward or a tax credit carryforward exists. The new standard is effective for interim and annual reporting periods beginning after December 15, 2013 and does not require any new financial statement disclosures. This new standard may be applied retrospectively or prospectively with early adoption permitted. The Company retrospectively adopted this new standard effective January 1, 2013.

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. On January 31, 2013, the Financial Accounting Standards Board issued an update to this standard clarifying that the scope includes derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or are subject to a master netting arrangement or similar agreement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and is required to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2013.

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. The new standard is applicable for all entities that issue financial statements that are presented in conformity with U.S. GAAP and that report items of other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2012 and is required to be applied prospectively. The Company adopted this new standard effective January 1, 2013.

3. Investment in Unconsolidated Affiliates and Related Party Transactions

On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight Group and CenterPoint Energy, Inc., agreed to form Enable Midstream Partners to own and operate the midstream businesses of OGE Energy and CenterPoint that will initially be structured as a private limited partnership. This transaction closed on May 1, 2013.
Pursuant to the Master Formation Agreement, OGE Energy and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex LLC to Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. Enogex LLC is a provider of integrated natural gas midstream services. Enogex LLC is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex LLC's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. CenterPoint Energy Field Services, LLC, a Delaware limited liability company and, prior to the closing of the transaction on May 1, 2013, a wholly owned subsidiary of CenterPoint, that provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States, was converted into a Delaware limited partnership that became Enable Midstream Partners, LP. CenterPoint contributed to Enable its equity interests in each of (i) CenterPoint Energy Gas Transmission Company, LLC, a Delaware limited liability company that is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Louisiana, Oklahoma and Texas, (ii) MRT, a Delaware limited liability company that is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Illinois and Missouri and (iii) certain of its other midstream subsidiaries and caused its subsidiary CenterPoint Energy Southeastern Pipelines Holding, LLC to contribute a 24.95 percent interest in Southeast Supply Header, LLC, a Delaware limited liability company. CenterPoint indirectly owned a 50 percent interest in Southeast Supply Header, LLC, which owns a 1.0 billion cubic feet per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama.
Immediately prior to closing, on May 1, 2013, the ArcLight group contributed $107.0 million and OGE Energy contributed $9.1 million to Enogex LLC in order to pay down short-term debt. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable.

CenterPoint has certain put rights, and Enable has certain call rights, exercisable with respect to any interest in Southeast Supply Header, LLC retained by CenterPoint following the formation of Enable Midstream Partners, under which CenterPoint would contribute to Enable Midstream Partners CenterPoint's retained interest in Southeast Supply Header, LLC at a price equal to the fair market value of such interest at the time the put right or call right is exercised. If CenterPoint were to exercise such put right or Enable were to exercise such call right, CenterPoint's retained interest in Southeast Supply Header, LLC would be contributed to Enable in exchange for consideration consisting of a specified number of limited partnership units and, subject to certain restrictions, a cash payment, payable either from

CenterPoint to Enable or from Enable to CenterPoint, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in Southeast Supply Header, LLC.

The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. CenterPoint and OGE Energy also own a 40 percent and 60 percent interest, respectively, in any incentive distribution rights to be held by the general partner of Enable following an initial public offering of Enable. In addition, for a period of time, the ArcLight group will have certain protective rights and approval rights over certain material activities of Enable, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets. The general partner of Enable will initially be governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy, Inc. and OGE Energy. Based on the

50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex Holdings LLC and began accounting for its interest in Enable using the equity method of accounting.
Pursuant to a Registration Rights Agreement dated as of May 1, 2013, OGE Energy and CenterPoint Energy, Inc. agreed to initiate the process for the sale of an equity interest in Enable in an initial public offering. Enable filed a registration statement for the initial public offering on November 26, 2013 and, subject to limited exceptions, plans to consummate the initial public offering during the first quarter of 2014. The initial public offering is subject to market conditions and OGE Energy can give no assurances that the initial public offering will be consummated.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

Subject to the exceptions provided below, pursuant to the terms of an Omnibus Agreement dated as of May 1, 2013 among OGE Energy, the ArcLight group and CenterPoint Energy, Inc., each of OGE Energy and CenterPoint Energy, Inc. will be required to hold or otherwise conduct all of its respective Midstream Operations (as defined below) located within the United States in Enable. This restriction will cease to apply to both OGE Energy and CenterPoint Energy, Inc. as soon as either OGE Energy or CenterPoint Energy, Inc. ceases to hold (i) any interest in the general partner of Enable or (ii) at least 20 percent of the limited partner interests of Enable. "Midstream Operations" generally means, subject to certain exceptions, the gathering, compression, treatment, processing, blending, transportation, storage, isomerization and fractionation of crude oil and natural gas, its associated production water and enhanced recovery materials such as carbon dioxide, and its respective constituents and the following products: methane, NGLs (Y-grade, ethane, propane, normal butane, isobutane and natural gasoline), condensate, and refined products and distillates (gasoline, refined product blendstocks, olefins, naphtha, aviation fuels, diesel, heating oil, kerosene, jet fuels, fuel oil, residual fuel oil, heavy oil, bunker fuel, cokes, and asphalts), to the extent such activities are located within the United States.
In addition, if OGE Energy or CenterPoint Energy, Inc. acquires any assets or equity of any person engaged in Midstream Operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired Midstream Operations that have not been offered to Enable), the acquiring party will be required to offer Enable the opportunity to acquire such assets or equity for such value; provided, that the acquiring party will not be obligated to offer any such assets or equity to Enable if the acquiring party intends to cease using them in Midstream Operations within 12 months. If Enable does not exercise its option, then the acquiring party will be free to retain and operate such Midstream Operations; provided, however, that if the fair market value of such Midstream Operations is greater than 66 2/3 percent of the fair market value of all of the assets being acquired in such transaction, then the acquiring party will be required to dispose of such Midstream Operations within 24 months.
As long as the ArcLight group has certain protective rights, the ArcLight group will be prohibited from pursuing any transaction independently from Enable (i) if the ArcLight group's consent is required for Enable to pursue such transaction and (ii) the ArcLight group affirmatively votes not to consent to such transaction.

On May 1, 2013, OGE Energy, OGE Holdings and Enable entered into a Seconding Agreement. During the term of the Seconding Agreement, OGE Holdings' employees will continue to perform services for Enable and its subsidiaries.

Distributions received from Enable were $51.7 million during the year ended December 31, 2013.

Related Party Transactions

As OGE Energy's interest in Enogex Holdings was deconsolidated on May 1, 2013, operating costs charged and related party transactions between the Company and its affiliate, Enable, after May 1, 2013, which were previously eliminated in consolidation, are discussed below.

OGE Energy charged operating costs to Enogex Holdings/Enable of $17.8 million during 2013. OGE Energy charges operating costs to its subsidiaries and unconsolidated affiliate based on several factors. Operating costs directly related to specific subsidiaries or unconsolidated affiliate are assigned to those subsidiaries or unconsolidated affiliate. Where more than one subsidiary or unconsolidated affiliate benefits from certain expenditures, the costs are shared between those subsidiaries and unconsolidated affiliate receiving the benefits. Operating costs incurred for the benefit of all subsidiaries and unconsolidated affiliate are allocated among the subsidiaries and unconsolidated affiliate, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Related Party Transactions with Enable

(In millions)	Eight Months Ended December 31, 2013
Operating Revenues:	
Electricity to power electric compression assets	$7.7
Cost of Sales:	
Natural gas transportation services	$23.2
Natural gas storage services	8.6
Natural gas purchases	14.8

Summarized Financial Information of Enable

As Enable began operations on May 1, 2013, summarized unaudited financial information for 100 percent of Enable is presented below at December 31, 2013 and for the eight months ended December 31, 2013.

Balance Sheet	December 31, 2013
	(In millions)
Current assets	$549
Non-current assets	10,683
Current liabilities	720
Non-current liabilities	2,331

Income Statement	Eight Months Ended December 31, 2013
	(In millions)
Operating revenues	$2,122.6
Cost of sales	1,240.5
Operating income	321.9
Net income	288.6

Enable concluded that the formation of Enable was considered a business combination, and CenterPoint Midstream was the acquirer of Enogex Holdings for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint Midstream for Enogex Holdings is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their fair value. Enogex Holdings' assets, liabilities and equity have accordingly been adjusted to estimated fair value as of May 1, 2013, resulting in an increase to equity of $2.2 billion. Determining the fair value of certain assets and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions. Enable utilized appraisers to assist in the determination of fair value of certain assets.

OGE Energy recorded equity in earnings of unconsolidated affiliates of $101.9 million for the eight months ended December 31, 2013. Equity in earnings of unconsolidated affiliates includes OGE Energy's 28.5 percent share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex and its underlying equity in net assets of Enable, based on historical cost as of May 1, 2013. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments described above.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates	Eight Months Ended December 31, 2013
	(In millions)
OGE's 28.5% share of Enable Net Income	$82.1
Amortization of basis difference	9.4
Elimination of Enogex Holdings fair value and other adjustments	10.4
OGE's Equity in earnings of unconsolidated affiliates	$101.9

4. Impairment of Assets

In August 2011, Enogex recorded a pre-tax impairment loss related to its Atoka joint venture which operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka, OK area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result Enogex recorded a pre-tax impairment loss of $5.0 million associated with the cost it had capitalized in connection with the installation of the leased plant as those costs were determined to be not recoverable through future cash flows. The noncontrolling interest portion of the pre-tax impairment loss was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

5. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The Company had no financial instruments measured at fair value on a recurring basis at December 31, 2013. The following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2012 as well as presents the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheet at December 31, 2012. There were no Level 3 investments held at December 31, 2012.

December 31, 2012

(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets (B)	Liabilities (C)
Quoted market prices in active market for identical assets (Level 1)	$5.0	$5.0	$—	$—
Significant other observable inputs (Level 2)	0.5	0.5	3.1	3.8
Total fair value	5.5	5.5	3.1	3.8
Netting adjustments	(5.0)	(5.2)	—	—
Total	$0.5	$0.3	$3.1	$3.8

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $5.9 million at December 31, 2012, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.2 million at December 31, 2012, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the fair value and carrying amount of the Company's financial instruments at December 31, 2013 and December 31, 2012.

December 31 (In millions)	2013 Carrying Amount	2013 Fair Value	2012 Carrying Amount	2012 Fair Value
Long-Term Debt				
OG&E Senior Notes	$2,154.5	$2,405.0	$1,904.2	$2,401.6
OG&E Industrial Authority Bonds	135.4	135.4	135.4	135.4
OG&E Tinker Debt	10.3	9.1	10.7	10.0

OGE Energy Senior Notes	99.9	103.1	99.9	106.3
Enogex LLC Senior Notes	(A)	(A)	448.4	493.4
Enogex LLC Term Loan	(A)	(A)	250.0	250.0

(A) As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company's consolidated financial statements do not include any obligations for the Enogex LLC Senior Notes and Enogex LLC Term Loan as of May 1, 2013.

The carrying value of the financial instruments included in the Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The fair value of the Company's long-term debt is based on

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quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

6. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivatives instruments is interest rate risk. The Company is also exposed to credit risk in its business operations.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company previously designated as cash flow hedges derivatives used to manage commodity price risk exposure for OGE Holdings's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). The Company also previously designated as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Due to the deconsolidation effective May 1, 2013, the Company had no instruments designated as cash flow hedges at December 31, 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At December 31, 2013 and 2012, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments were utilized in OGE Holdings' asset management activities and were reflected in consolidated results prior to the deconsolidation of Enogex on May 1, 2013. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in the period in which it occurred.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2013, the Company has no derivative instruments that were designated as cash flow hedges.

At December 31, 2012, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2012 Gross Notional Volume (A)
Enogex hedges	
Natural gas sales	3.7

(A) Natural gas in MMBtu's.

At December 31, 2012, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural gas (B)		
Physical (C)(D)	7.0	30.1
Fixed Swaps/Futures	16.2	17.9
Basis Swaps	7.3	6.7

(A) Natural gas in MMBtu's.
(B) 95.1 percent of the natural gas contracts have durations of one year or less, 2.9 percent have durations of more than one year and less than two years and 2.0 percent have durations of more than two years.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The Company had no derivative instruments included in its Consolidated Balance Sheet at December 31, 2013. The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2012 are as follows:

Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$—	$0.5
Total		$—	$0.5
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$0.1	$—
	Other Current Assets	5.0	4.7
Physical Purchases/Sales	Current PRM	0.4	0.3
Total		$5.5	$5.0
Total Gross Derivatives (A)		$5.5	$5.5

(A) See Note 5 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2012.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2013.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	$(0.2)	$5.2	$—
Interest Rate Swap	—	(0.2)	—
Total	$(0.2)	$5.0	$—

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(6.1)
Natural Gas Financial Futures/Swaps	1.0
Total	$(5.1)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2012.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	0.5	5.2	—
Interest Rate Swap	—	(0.4)	—
Total	$0.5	$4.8	$—

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(11.7)
Natural Gas Financial Futures/Swaps	1.1
Total	$(10.6)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2011.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
NGLs Financial Options	$(8.4)	$(9.8)	$—
Natural Gas Financial Futures/Swaps	2.9	(30.4)	—

Interest Rate Swap	—	(0.4	) —
Total	$ (5.5	) $ (40.6	) $ —

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Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$(10.0)
Natural Gas Financial Futures/Swaps	0.4
Total	$(9.6)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2012 and 2011, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2012 and 2011, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

At December 31, 2013, the Company had no derivative instruments that contain credit-risk related contingent features. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2012, the Company would have been required to post $0.2 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that were in a net liability position at December 31, 2012.

7. Stock-Based Compensation

In 2013, the Company adopted, and its shareowners approved, the 2013 Stock Incentive Plan. The 2013 Plan replaced the 2008 Plan and no further awards will be granted under the 2008 Plan. Under the 2013 Stock Incentive Plan, restricted stock, restricted stock units, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 7,400,000 shares under the 2013 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2013, 2012 and 2011 related to the Company's performance units and restricted stock.

Year ended December 31 (In millions)	2013	2012	2011
Performance units			
Total shareholder return	$8.4	$8.0	$8.2
Earnings per share	2.3	4.2	5.5
Total performance units	10.7	12.2	13.7
Restricted stock	0.4	0.6	1.0
Total compensation expense	11.1	12.8	14.7
Less: Amount paid by unconsolidated affiliates	3.1	—	—
Net compensation expense	$8.0	$12.8	$14.7
Income tax benefit	$3.1	$4.9	$5.7

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2013, 2012 and 2011, there were 548,344 shares, 849,110 shares and 623,246 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2013, there were 11,318 shares of restricted stock returned to the Company to satisfy tax liabilities.

Performance Units

Under the 2008 Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the 2008 Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the

Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share growth over a three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of these performance units are classified as equity in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

As a result of the formation of Enable on May 1, 2013, 2013 performance unit grants to OGE Holdings' employees that were previously based on earnings before interest, taxes, depreciation and amortization were converted to performance units based on total shareholder return or earnings per share. Total 2013 performance unit grants converted were 91,390, comprised of 45,596 total shareholder return performance units with a $25.89 grant date fair value and 45,794 earnings per share performance units with a $26.73 grant date fair value. As a result of a modification to the 2012 performance unit grants, 2012 performance unit grants to OGE Holdings' employees that were previously based on earnings before interest, taxes and depreciation and amortization were converted to performance units based on total shareholder return or earnings per share. Total 2012 performance unit grants converted were 82,930, comprised of 41,554 total shareholder return performance units with a $47.71 grant date fair value and 41,376 earnings per share performance units with a $34.94 grant date fair value. The amount of these performance units were adjusted for the effects of the stock split. The impact of the modification of the performance unit grants on stock-based compensation expense for 2013 was not material.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2013	2012	2011
Number of units granted	316,162	338,678	427,442
Fair value of units granted	$25.89	$25.91	$23.05

Expected dividend yield	2.8 %	3.0 %	3.2 %
Expected price volatility	20.0 %	22.0 %	33.0 %
Risk-free interest rate	0.37 %	0.38 %	1.40 %
Expected life of units (in years)	2.84	2.87	2.87

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2013	2012	2011
Number of units granted	74,570	81,594	142,476
Fair value of units granted	$26.73	$23.82	$20.81

Restricted Stock

Under the 2008 Stock Incentive Plan and beginning in 2008, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2013	2012	2011
Shares of restricted stock granted	5,940	10,824	35,804
Fair value of restricted stock granted	$29.71	$26.72	$24.41

A summary of the activity for the Company's performance units and restricted stock at December 31, 2013 and changes in 2013 are shown in the following table.

	Performance Units							
	Total Shareholder Return			Earnings Per Share			Restricted Stock	
(dollars in millions)	Number of Units		Aggregate Intrinsic Value	Number of Units		Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
Units/Shares Outstanding at 12/31/12	1,069,128			327,838			49,106	
Granted	316,162	(A)		74,570	(A)		5,940	
Modification	87,150	(B)		87,170	(B)		N/A	
Converted	(377,266)	(C)	$22.1	(125,760)	(C)	$7.4	N/A	
Vested	N/A			N/A			(30,242)	$0.9
Forfeited	(33,114)			(9,792)			(1,176)	
Units/Shares Outstanding at 12/31/13	1,062,060		$50.9	354,026		$13.9	23,628	$0.8
Units/Shares Fully Vested at 12/31/13	355,078		$19.3	118,350		$8.0		

(A)

For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

(B) These amounts represent the performance unit grants previously based on earnings before interest, taxes, depreciation and amortization that were converted to performance units based on total shareholder return or earnings per share as a result of the formation of Enable.

(C) These amounts represent performance units that vested at December 31, 2012 which were settled in February 2013.

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A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2013 and changes in 2013 are shown in the following table.

	Performance Units						Restricted Stock	
	Total Shareholder Return			Earnings Per Share				
	Number of Units		Weighted-Average Grant Date Fair Value	Number of Units		Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/Shares Non-Vested at 12/31/12	691,862		$ 24.40	202,078		$ 22.00	49,106	$ 23.61
Granted	316,162	(A)	$ 25.89	74,570	(A)	$ 26.73	5,940	$ 29.71
Modification	87,150	(B)	$ 36.29	87,170	(B)	$ 30.62	N/A	N/A
Vested	(355,078)		$ 23.05	(118,350)		$ 20.81	(30,242)	$ 22.57
Forfeited	(33,114)		$ 24.96	(9,792)		$ 23.34	(1,176)	$ 26.87
Units/Shares Non-Vested at 12/31/13	706,982		$ 25.90	235,676		$ 25.28	23,628	$ 26.30
Units/Shares Expected to Vest	633,808	(C)		209,938	(C)		23,628	

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

(B) These amounts represent the performance unit grants previously based on earnings before interest, taxes, depreciation and amortization that were converted to performance units based on total shareholder return or earnings per share as a result of the formation of Enable.

(C) The intrinsic value of the performance units based on total shareholder return and earnings per share is $28.3 million and $5.6 million, respectively.

Fair Value of Vested Performance Units and Restricted Stock

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

Year ended December 31 (In millions)	2013	2012	2011
Performance units			
Total shareholder return	$8.2	$7.4	$7.4
Earnings per share	4.9	4.1	3.9
Restricted stock	0.7	0.7	1.0

Unrecognized Compensation Cost

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2013	Unrecognized Compensation Cost (in millions)	Weighted Average to be Recognized (in years)
Performance units		
Total shareholder return	$8.4	1.63
Earnings per share	1.8	1.49
Total performance units	10.2	
Restricted stock	0.2	1.63
Total	$10.4	

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Stock Options

The Company last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for the Company's stock options at December 31, 2013 and changes during 2013 are shown in the following table.

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/12	39,200	$11.40		
Exercised	(39,200)	$(11.40)	$1.4	
Options Outstanding at 12/31/13	—	$—	$—	0.00 years
Options Fully Vested and Exercisable at 12/31/13	—	$—	$—	0.00 years

A summary of the activity for the Company's exercised stock options in 2013, 2012 and 2011 are shown in the following table.

Year ended December 31 (In millions)	2013	2012	2011
Intrinsic value (A)	$1.4	$2.0	$2.2
Cash received from stock options exercised	0.4	0.8	1.3

(A) The difference between the market value on the date of exercise and the option exercise price.

8. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but which did not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year ended December 31 (In millions)	2013	2012	2011
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Installment payments for Tinker electric distribution system	$—	$10.6	$—
Power plant long-term service agreement	9.7	—	1.7
Investment in Enable (Note 3)	1,248.6	—	—
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized) (A)	$151.1	$161.3	$138.9
Income taxes (net of income tax refunds)	(1.1)	(9.1)	4.7

(A) Net of interest capitalized of $5.4 million, $8.0 million and $19.1 million in 2013, 2012 and 2011, respectively.

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9. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 (In millions)	2013	2012	2011
Provision (Benefit) for Current Income Taxes			
Federal	$—	$(9.1)	$(5.4)
State	4.3	0.5	0.1
Total Provision (Benefit) for Current Income Taxes	4.3	(8.6)	(5.3)
Provision for Deferred Income Taxes, net			
Federal	154.4	147.3	165.5
State	(26.4)	(1.5)	3.8
Total Provision for Deferred Income Taxes, net	128.0	145.8	169.3
Deferred Federal Investment Tax Credits, net	(2.0)	(2.1)	(3.3)
Total Income Tax Expense	$130.3	$135.1	$160.7

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2010 or state and local tax examinations by tax authorities for years prior to 2009. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both Federal and Oklahoma state tax credits associated with production from its wind farms. In addition, OG&E and Enable earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	2013	2012	2011
Statutory Federal tax rate	35.0 %	35.0 %	35.0 %
Amortization of net unfunded deferred taxes	0.6	0.8	0.7
State income taxes, net of Federal income tax benefit	0.4	(0.1)	0.6
Federal investment tax credits, net	(0.4)	(0.4)	(0.7)
401(k) dividends	(0.5)	(0.5)	(0.5)
Income attributable to noncontrolling interest	(0.3)	(1.6)	(1.3)
Federal renewable energy credit (A)	(7.2)	(7.2)	(3.4)
Uncertain tax positions	1.5	—	—
Remeasurement of state deferred tax liabilities	(4.1)	—	—
Other	(0.1)	—	0.3
Effective income tax rate	24.9 %	26.0 %	30.7 %

(A) Represents credits associated with the production from OG&E's wind farms.

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The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2013 and 2012, respectively, were as follows:

December 31 (In millions)	2013	2012
Current Deferred Income Tax Assets		
Net operating losses	$180.1	$152.4
Accrued liabilities	22.3	27.1
Federal tax credits	8.0	6.0
Accrued vacation	4.7	3.8
Uncollectible accounts	0.7	1.0
Total Current Deferred Income Tax Assets	215.8	190.3
Current Accrued Income Tax Liabilities		
Derivative instruments	—	(2.6)
Total Current Accrued Income Tax Liabilities	—	(2.6)
Current Deferred Income Tax Assets, net	$215.8	$187.7
Non-Current Deferred Income Tax Liabilities		
Accelerated depreciation and other property related differences	$1,753.3	$1,660.3
Investment in Enogex Holdings	—	638.0
Investment in Enable Midstream Partners	630.5	—
Company pension plan	55.1	52.4
Income taxes refundable to customers, net	21.9	21.2
Regulatory asset	26.1	18.8
Bond redemption-unamortized costs	3.6	4.0
Derivative instruments	1.6	1.5
Total Non-Current Deferred Income Tax Liabilities	2,492.1	2,396.2
Non-Current Deferred Income Tax Assets		
Federal tax credits	(105.2)	(69.6)
State tax credits	(92.6)	(83.7)
Postretirement medical and life insurance benefits	(62.8)	(57.6)
Regulatory liabilities	(61.3)	(71.4)
Asset retirement obligations	(20.8)	—
Net operating losses	(18.8)	(159.1)
Other	(4.6)	(4.5)
Deferred Federal investment tax credits	(0.7)	(1.5)
Total Non-Current Deferred Income Tax Assets	(366.8)	(447.4)
Non-Current Deferred Income Tax Liabilities, net	$2,125.3	$1,948.8

As of December 31, 2013, the Company has classified $7.8 million of unrecognized tax benefits as a reduction of deferred tax assets recorded. Management is currently unaware of any issues under review that could result in significant additional payments, accruals, or other material deviation from this amount.

Following is a reconciliation of the Company's total gross unrecognized tax benefits as of the years ended December 31, 2013, 2012, and 2011.

(Millions)	2013	2012	2011
Balance at January 1	$—	$—	$—
Tax positions related to current year:			
Additions	2.7	—	—
Tax positions related to prior years:			
Additions	5.1	—	—
Balance at December 31	$7.8	$—	$—

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other operation and maintenance expense, respectively. During the year ended December 31, 2013, there were no income tax-related interest or penalties recorded with regard to uncertain tax positions. The total amount of unrecognized tax benefits that would impact the effective tax rate, if recognized, was $7.8 million as of December 31, 2013.
As previously reported, in January 2013, OG&E determined that a portion of certain Oklahoma investment tax credits previously recognized but not yet utilized may not be available for utilization in future years. During the first quarter of 2013, OG&E recorded a reserve of $7.8 million ($5.1 million after tax) related to a portion of the Oklahoma investment tax credits generated in years prior to 2013 but not yet utilized due to management's determination that it is more likely than not that it will be unable to utilize these credits. An additional reserve of $4.1 million ($2.7 million after tax) was established with regard to these credits generated in the current year.

Prior to 2013, the Company had a Federal tax operating loss primarily caused by the accelerated tax "bonus" depreciation provision contained within the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which allowed the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service in 2011 and 50 percent for certain property placed into service in 2012. During 2013, the Company began to utilize these net operating losses.

On January 2, 2013, the American Taxpayer Relief Act of 2012 was signed into law. Among other things, the law included an extension of bonus depreciation for one year for property generally placed in service before January 1, 2014. The impact of the new law was reflected in the Company's 2013 Consolidated Financial Statements as an increase in Deferred Tax Liabilities with a corresponding increase in Deferred Tax Assets related to the net operating loss.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium could not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year period, affected credits generated by the Company were deferred and will be utilized at a future date. For financial accounting purposes, the Company is receiving the benefits as most of these credits did not expire if they were not utilized in the period they were generated.

Other

The Company sustained Federal and state tax operating losses through 2012 caused primarily by bonus depreciation and other book verses tax temporary differences. As a result, the Company had accrued Federal and state income tax benefits carrying into 2013. As the Company can no longer carry these losses back to prior periods, these losses are being carried forward for utilization in future years. In addition to the operating losses, the Company was unable to utilize the various tax credits that were generating during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. Under current law, the Company anticipates future taxable income will be sufficient to utilize all of the losses and credits before they begin to expire, accordingly no valuation allowance is considered necessary. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
Net operating losses			
State operating loss	$893.6	$32.8	2030
Federal operating loss	474.6	166.1	2030
Federal tax credits	113.2	113.2	2029
State tax credits			
Oklahoma investment tax credits	106.1	69.0	N/A
Oklahoma capital investment board credits	7.3	7.3	N/A
Oklahoma zero emission tax credits	24.3	16.3	2020

Acquisition of the equity interest in Enable on May 1, 2013, is also expected to increase the Company's utilization of state net operating loss carryforwards. Under current tax law, the Company projects full utilization of all Federal operating losses in 2014 as well as partial utilization of State operating loss carryforwards. Accordingly, a current deferred tax asset of $180.1 million has been reflected on the balance sheet.

As a result of acquiring an equity interest in Enable, the Company has a lower effective tax rate in conjunction with the formation of Enable in states with lower state tax rates. Remeasurement of state deferred tax expense to reflect these lower rates reduced income tax expense for 2013 by $8.4 million. In addition, deferred tax adjustments related to the Company's deconsolidation of Enogex Holdings increased income tax expense for 2013 by $3.9 million.

During 2013, the Company recognized a $16.4 million reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of an employment company within Enable.

10. Common Equity

Forward Stock Split

On May 16, 2013, the Company's Board of Directors approved a 2-for-1 forward stock split of the Company's common stock, effective July 1, 2013, which entitled each shareholder of record to receive two shares for every one share of Company stock owned by the shareholder. In connection with the stock split, an amendment to the Company's Articles of Incorporation was approved on May 16, 2013 which increased the number of authorized shares of common stock from 225 million to 450 million. All share and per share amounts presented within this Form 10-K reflect the effects of the stock split.

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 399,485 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013 and received proceeds of $13.8 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At December 31, 2013, there were 3,845,503 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income attributable to OGE Energy by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions)	2013	2012	2011
Net Income Attributable to OGE Energy	$387.6	$355.0	$342.9
Average Common Shares Outstanding			
Basic average common shares outstanding	198.2	197.1	195.8
Effect of dilutive securities:			
Contingently issuable shares (performance units)	1.2	1.0	2.7
Diluted average common shares outstanding	199.4	198.1	198.5
Basic Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	$1.96	$1.80	$1.75
Diluted Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	$1.94	$1.79	$1.73

11. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2013, the Company was in compliance with all of its debt agreements.

OG&E Industrial Authority Bonds

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds on any business day. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES			DATE DUE	AMOUNT (In millions)
0.18%	-	0.34%	Garfield Industrial Authority, January 1, 2025	$47.0
0.10%	-	0.39%	Muskogee Industrial Authority, January 1, 2025	32.4
0.10%	-	0.30%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)				$135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as long-term debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Issuance of Long-Term Debt

On May 8, 2013, OG&E issued $250 million of 3.9% senior notes due May 1, 2043. The proceeds from the issuance were added to OG&E's general funds and were used to repay short-term debt, fund capital expenditures, general corporate expenses and for working capital purposes. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $100.2 million, $0.2 million, $110.2 million, $125.1 million and $250.1 million in years 2014, 2015, 2016, 2017 and 2018, respectively.

The Company has previously incurred costs related to debt refinancings. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset, unamortized debt expense is classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

12. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $439.6 million and $430.9 million at December 31, 2013 and 2012, respectively, at a weighted-average interest rate of 0.30 percent and 0.43 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2013.

Entity	Aggregate Commitment (In millions)	Amount Outstanding (A)	Weighted-Average Interest Rate		Maturity	
OGE Energy (B)	$750.0	$439.6	0.30	% (D)	December 13, 2017	(E)
OG&E (C)	400.0	2.1	0.53	% (D)	December 13, 2017	(E)
	1,150.0	441.7	0.30	%		
Cash	6.8	N/A	N/A		N/A	
Total	$1,156.8	$441.7	0.30	%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2013.

(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.

(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.

(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

(E) In December 2011, the Company and OG&E entered into unsecured five-year revolving credit agreements to total in the aggregate $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year, subject to consent of a specified percentage of the lenders. Effective July 29, 2013, the Company and OG&E utilized one of these one-year extensions, and received consent from all of the lenders, to extend the maturity of their credit agreements to December 13, 2017.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2013 and ending December 31, 2014.

13. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. During both 2013 and 2012, OGE Energy made contributions to its Pension Plan of $35 million to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2014, OGE Energy expects to contribute up to $26 million to its Pension Plan. The expected contribution to the Pension Plan during 2014 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization’s net periodic pension cost. During 2013, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement. As a result, and based in part on the Company’s historical experience regarding eligible employees who elect to retire in the last quarter of a particular year, the Company recorded pension settlement charges of $22.4 million in the fourth quarter of 2013, of which $17.0 million related to OG&E’s Oklahoma jurisdiction and has been included in the pension tracker. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company’s total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

The following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2013 and 2012. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan	
December 31 (In millions)	2013	2012	2013	2012
Benefit obligations	$(658.1)	$(747.1)	$(14.0)	$(14.5)
Fair value of plan assets	654.9	626.0	—	—
Funded status at end of year	$(3.2)	$(121.1)	$(14.0)	$(14.5)

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

(In millions)	Projected Benefit Payments
2014	$93.2
2015	82.0
2016	76.7
2017	71.7
2018	64.7
After 2018	270.1

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	<90%	95%	100%	105%	110%	115%	120%
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	Target Allocation	Minimum	Maximum
Domestic All-Cap/Large Cap Equity	50%	50%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	15%	5%	25%
International Equity	20%	10%	30%

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three percent to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Core Fixed Income	Barclays Capital Aggregate Index
Interest Rate Sensitive Fixed Income	Barclays Capital Aggregate Index
Long Duration Fixed Income	Barclays Long Government/Credit
Equity Index	Standard & Poor's 500 Index
All-Cap Equity	Russell 3000 Index
	Russell 3000 Value Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital Investment ACWI ex-US

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded:

options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of the Company's Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2013 and 2012. There were no Level 3 investments held by the Pension Plan at December 31, 2013 and 2012.

(In millions)	December 31, 2013	Level 1	Level 2
Common stocks			
U.S. common stocks	$236.8	$236.8	$—
Foreign common stocks	39.3	39.3	—
U.S. Government obligations			
U.S. treasury notes and bonds (A)	159.8	159.8	—
Mortgage-backed securities	50.3	—	50.3
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	110.6	—	110.6
Mortgage-backed securities	22.3	—	22.3
Commingled fund (C)	29.2	—	29.2
Common/collective trust (D)	26.0	—	26.0
Foreign government bonds	4.0	—	4.0
U.S. municipal bonds	2.0	—	2.0
Interest-bearing cash	0.1	0.1	—
Forward contracts			
Receivable (foreign currency)	1.1	—	1.1
Payable (foreign currency)	(1.1)	—	(1.1)
Total Plan investments	$680.4	$436.0	$244.4
Receivable from broker for securities sold	11.5		
Interest and dividends receivable	3.2		
Payable to broker for securities purchased	(40.2)		
Total Plan assets	$654.9		

(In millions)	December 31, 2012	Level 1	Level 2
Common stocks			
U.S. common stocks	$232.2	$232.2	$—
Foreign common stocks	39.9	39.9	—
U.S. Government obligations			
U.S. treasury notes and bonds (A)	138.6	138.6	—
Mortgage-backed securities	55.8	—	55.8
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	98.4	—	98.4
Mortgage-backed securities	13.5	—	13.5
Commingled fund (C)	34.9	—	34.9
Common/collective trust (D)	25.6	—	25.6
Foreign government bonds	3.9	—	3.9
U.S. municipal bonds	0.8	—	0.8
Interest-bearing cash	0.2	0.2	—
Preferred stocks (foreign)	—	—	—
Forward contracts			
Receivable (foreign currency)	0.4	—	0.4
Payable (foreign currency)	(0.4)	—	(0.4)
Total Plan investments	$643.8	$410.9	$232.9
Receivable from broker for securities sold	0.8		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(21.4)		
Total Plan assets	$626.0		

(A) This category represents U.S. treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.

(B) This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings.

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

(D) This category represents units of participation in an investment pool which primarily invests in foreign or domestic bonds, debentures, mortgages, equipment or other trust certificates, notes, obligations issued or guaranteed by the U.S. Government or its agencies, bank certificates of deposit, bankers' acceptances and repurchase agreements, high grade commercial paper and other instruments with money market characteristics with a fixed or variable interest rate. There are no restrictions on redemptions in the common/collective trust.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, other U.S. Government obligations, commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, a repurchase agreement, money market fund and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The Company's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. The Company provides Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2013 and 2012. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2013 and 2012.

(In millions)	December 31, 2013	Level 1	Level 3
Group retiree medical insurance contract (A)	$53.1	$—	$53.1
Mutual funds investment			
U.S. equity investments	7.9	7.9	—
Money market funds investment	0.4	0.4	—
Total Plan investments	$61.4	$8.3	$53.1

(In millions)	December 31, 2012	Level 1	Level 3
Group retiree medical insurance contract (A)	$53.3	$—	$53.3
Mutual funds investment			
U.S. equity investments	6.0	6.0	—
Money market funds investment	0.3	0.3	—
Total Plan investments	$59.6	$6.3	$53.3

(A) This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

Year ended December 31 (In millions)	2013
Group retiree medical insurance contract	
Beginning balance	$53.3
Net unrealized gains related to instruments held at the reporting date	(0.5)
Interest income	1.1
Dividend income	0.6
Realized gains	0.4
Administrative expenses and charges	(0.1)
Claims paid	(1.7)
Ending balance	$53.1

The following table presents the status of the Company's postretirement benefit plans at December 31, 2013 and 2012. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

December 31 (In millions)	2013	2012
Benefit obligations	$(258.2)	$(301.0)
Fair value of plan assets	61.4	59.6
Funded status at end of year	$(196.8)	$(241.4)

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 8.35 percent in 2014 with the rates trending downward to 4.48 percent by 2028. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

Year ended December 31 (In millions)	2013	2012	2011
Effect on aggregate of the service and interest cost components	$—	$—	$—
Effect on accumulated postretirement benefit obligations	0.1	0.1	0.1

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 (In millions)	2013	2012	2011
Effect on aggregate of the service and interest cost components	$0.1	$0.1	$0.1
Effect on accumulated postretirement benefit obligations	0.6	0.9	0.6

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits.

(In millions)	Gross Projected Postretirement Benefit Payments
2014	$ 15.5
2015	16.1
2016	16.7
2017	17.2
2018	17.7
After 2018	90.7

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for 2013 and 2012. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2013 was $623.4 million and $12.9 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2012 was $705.2 million and $12.7 million, respectively. The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

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	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 (In millions)	2013	2012	2013	2012	2013	2012
Change in Benefit Obligation						
Beginning obligations	$(747.1)	$(697.7)	$(14.5)	$(13.3)	$(301.0)	$(280.6)
Service cost	(19.0)	(17.9)	(1.2)	(1.0)	(4.3)	(4.1)
Interest cost	(26.7)	(30.1)	(0.5)	(0.6)	(10.3)	(11.9)
Plan amendments	—	—	—	—	—	—
Plan settlements	67.5	—	—	—	—	—
Participants' contributions	—	—	—	—	(3.4)	(3.5)
Medicare subsidies received	—	—	—	—	—	(0.5)
Actuarial gains (losses)	53.0	(61.4)	2.0	(1.8)	46.7	(12.9)
Benefits paid	14.2	60.0	0.2	2.2	14.1	12.5
Ending obligations	$(658.1)	$(747.1)	$(14.0)	$(14.5)	$(258.2)	$(301.0)
Change in Plans' Assets						
Beginning fair value	$626.0	$589.8	$—	$—	$59.6	$61.0
Actual return on plans' assets	75.6	61.2	—	—	3.7	4.5
Employer contributions	35.0	35.0	0.2	2.2	8.8	2.6
Plan settlements	(67.5)	—	—	—	—	—
Participants' contributions	—	—	—	—	3.4	3.5
Medicare subsidies received	—	—	—	—	—	0.5
Benefits paid	(14.2)	(60.0)	(0.2)	(2.2)	(14.1)	(12.5)
Ending fair value	$654.9	$626.0	$—	$—	$61.4	$59.6
Funded status at end of year	$(3.2)	$(121.1)	$(14.0)	$(14.5)	$(196.8)	$(241.4)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31 (In millions)	2013	2012	2011	2013	2012	2011	2013	2012	2011
Service cost	$19.0	$17.9	$17.6	$1.2	$1.0	$1.0	$4.3	$4.1	$3.5
Interest cost	26.7	30.1	33.3	0.5	0.6	0.6	10.3	11.9	12.5
Expected return on plan assets	(48.4)	(46.0)	(45.5)	—	—	—	(2.5)	(3.0)	(5.1)
Amortization of transition obligation	—	—	—	—	—	—	—	2.7	2.7
Amortization of net loss	26.5	23.8	19.2	0.4	0.4	0.4	21.5	20.6	18.3
Amortization of unrecognized prior service cost (A)	1.8	2.2	2.4	0.3	0.7	0.7	(16.5)	(16.5)	(16.5)
Settlement	22.4	—	—	—	0.9	—	—	—	—
Total net periodic benefit cost	48.0	28.0	27.0	2.4	3.6	2.7	17.1	19.8	15.4
Less: Amount paid by unconsolidated affiliates	5.9	—	—	0.1	—	—	1.5	—	—
Net periodic benefit cost (B)	$42.1	$28.0	$27.0	$2.3	$3.6	$2.7	$15.6	$19.8	$15.4

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $60.0 million, $51.4 million and $45.1 million and of net periodic benefit cost recognized in 2013, 2012 and 2011, respectively, the Company recognized the following:

- an increase in pension expense in 2013, 2012 and 2011 of $5.8 million, $8.3 million and $10.8 million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction, which are included in the Pension tracker regulatory asset or liability (see Note 1); and
- an increase in postretirement medical expense in 2013, 2012 and 2011 of $0.6 million, $0.8 million and $3.5 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory asset or liability (see Note 1);
- a deferral of pension expense in 2013 of $17.0 million related to the pension settlement charge of $22.4 million, in accordance with the Oklahoma pension tracker.

The capitalized portion of the net periodic pension benefit cost was $5.7 million, $6.5 million and $6.1 million at December 31, 2013, 2012 and 2011, respectively. The capitalized portion of the net periodic postretirement benefit cost was $3.5 million, $5.5 million and $3.8 million at December 31, 2013, 2012 and 2011, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	2013	2012	2011	2013	2012	2011
Discount rate	4.60 %	3.70 %	4.50 %	4.60 %	3.60 %	4.50 %
Rate of return on plans' assets	8.00 %	8.00 %	8.00 %	4.00 %	4.00 %	6.50 %
Compensation increases	4.20 %	4.20 %	4.40 %	N/A	N/A	N/A
Assumed health care cost trend:						
Initial trend	N/A	N/A	N/A	8.35 %	8.55 %	8.75 %
Ultimate trend rate	N/A	N/A	N/A	4.48 %	4.48 %	4.48 %
Ultimate trend year	N/A	N/A	N/A	2028	2028	2028

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.00 percent in 2012 and 2013 in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was $1.6 million and $2.6 million at December 31, 2013 and 2012, respectively.

401(k) Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $14.2 million, $13.4 million and $12.3 million in 2013, 2012 and 2011, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2013, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. The Company accounts for the contributions related to the

Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limitations of the Code.

14. Report of Business Segments

Prior to May 1, 2013, the Company's business was divided into three segments as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight Group and CenterPoint Energy, Inc., agreed to form Enable Midstream Partners to own and operate the midstream businesses of OGE Energy and CenterPoint that will initially be structured as a private limited partnership. The transaction closed on May 1, 2013. As a result, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex Holdings LLC and began accounting for its interest in Enable using the equity method of accounting. The Company's business is now divided into two segments for financial reporting purposes as follows: (i) electric utility and (ii) natural gas midstream operations. The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. Equity in earnings of unconsolidated affiliates in the natural gas midstream operations segment includes OGE Energy's equity interest in Enable from May 1, 2013 through December 31, 2013. Operating income for the natural gas midstream operations segment represents results of operations for Enogex Holdings LLC through April 30, 2013. Investment in unconsolidated affiliates in the natural gas midstream operations segment represents OGE Energy's investment in Enable at December 31, 2013. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income and equity in earnings of unconsolidated affiliates as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments for the years ended December 31, 2013, 2012 and 2011.

2013	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$2,262.2	$630.4	$—	$(24.9)	$2,867.7
Cost of sales	965.9	489.0	—	(26.0)	1,428.9
Other operation and maintenance	438.8	60.9	(10.5)	—	489.2
Depreciation and amortization	248.4	36.8	12.1	—	297.3
Taxes other than income	83.8	10.5	4.5	—	98.8
Operating income (loss)	$525.3	$33.2	$(6.1)	$1.1	$553.5
Equity in earnings of unconsolidated affiliates	$—	$101.9	$—	$—	$101.9
Investment in unconsolidated affiliates (at historical cost)	$—	$1,298.8	$—	$—	$1,298.8
Total assets	$7,694.9	$1,348.6	$216.2	$(125.0)	$9,134.7
Capital expenditures	$797.6	$181.5	$11.5	$—	$990.6

2012	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$2,141.2	$1,608.6	$—	$(78.6)	$3,671.2
Cost of sales	879.1	1,120.1	—	(80.5)	1,918.7
Other operation and maintenance	446.3	172.9	(17.7)	—	601.5
Depreciation and amortization	248.7	108.8	13.5	—	371.0
Impairment of assets	—	0.4	—	—	0.4
Gain on insurance proceeds	—	(7.5)	—	—	(7.5)

Taxes other than income	77.7	28.3	4.2	—	110.2
Operating income (loss)	$489.4	$185.6	$—	$1.9	$676.9
Total assets	$7,222.4	$2,681.3	$242.6	$(224.1)	$9,922.2
Capital expenditures	$704.4	$506.5	$18.3	$—	$1,229.2

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2011	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$2,211.5	$1,787.1	$—	$(82.7)	$3,915.9
Cost of sales	1,013.5	1,346.6	—	(82.2)	2,277.9
Other operation and maintenance	436.0	162.5	(17.3)	—	581.2
Depreciation and amortization	216.1	77.6	13.4	—	307.1
Impairment of assets	—	6.3	—	—	6.3
Gain on insurance proceeds	—	(3.0)	—	—	(3.0)
Taxes other than income	73.6	22.0	4.1	—	99.7
Operating income (loss)	$472.3	$175.1	$(0.2)	$(0.5)	$646.7
Total assets	$6,620.9	$2,289.0	$155.0	$(158.9)	$8,906.0
Capital expenditures	$844.5	$612.5	$13.8	$—	$1,470.8

15. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases, OG&E wind farm land leases and OGE Energy noncancellable operating lease. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 (In millions)	2014	2015	2016	2017	2018	After 2018	Total
Operating lease obligations							
Railcars	$3.8	$3.1	$27.3	$—	$—	$—	$34.2
Wind farm land leases	2.1	2.1	2.1	2.4	2.4	48.8	59.9
OGE Energy noncancellable operating lease	0.8	0.8	0.8	0.8	0.7	—	3.9
Total operating lease obligations	$6.7	$6.0	$30.2	$3.2	$3.1	$48.8	$98.0

Payments for operating lease obligations were $8.8 million, $14.2 million and $10.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million. OG&E is also required to maintain all of the railcars it has under the operating lease and has entered into an agreement with a non-affiliated company to furnish this maintenance.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. OG&E has a unilateral right to terminate this lease upon a 6-month notice effective April 2015 and April 2016.

OG&E Wind Farm Land Lease Agreements

OG&E has wind farm land operating leases for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their economic life.

OGE Energy Noncancellable Operating Lease

On August 29, 2012, OGE Energy executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five-years and allows for leasehold improvements.

OGE Holdings Noncancellable Operating Lease

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company has no obligations included in its Consolidated Financial Statements at December 31, 2013 under OGE Holdings' noncancellable lease obligations previously disclosed in the Company's 2012 Form 10-K.

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

(In millions)	2014	2015	2016	2017	2018	Total
Other purchase obligations and commitments						
Cogeneration capacity and fixed operation and maintenance payments	$85.1	$82.7	$81.9	$79.6	$77.0	$406.3
Expected cogeneration energy payments	61.1	60.9	75.7	81.5	87.4	366.6
Minimum fuel purchase commitments	451.8	451.8	368.5	385.1	—	1,657.2
Expected wind purchase commitments	58.0	58.9	59.8	60.8	59.5	297.0
Long-term service agreement commitments	70.5	2.8	2.5	2.6	19.1	97.5
Total other purchase obligations and commitments	$726.5	$657.1	$588.4	$609.6	$243.0	$2,824.6

Public Utility Regulatory Policy Act of 1978

At December 31, 2013, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2013, 2012 and 2011, OG&E made total payments to cogenerators of $134.8 million, $135.1 million and $140.7 million, respectively, of which $74.4 million, $77.1 million and $78.0 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Sales.

OG&E Minimum Fuel Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $657.3 million, $585.6 million and $647.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. OG&E has coal contracts for purchases from through December 2016. OG&E has entered into multiple month term natural gas contracts for 31.5 percent of its 2014 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2014 natural gas requirements will be acquired through additional requests for proposal in early to mid-2014, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm, (iii) the 227.5 MW Crossroads wind farm, (iv) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (vi) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030 and (vii) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2013, 2012 and 2011.

Year ended December 31 (In millions)	2013	2012	2011
CPV Keenan	$30.9	$25.1	$24.5
Edison Mission Energy	20.6	20.2	8.5
FPL Energy	3.3	3.4	3.7
NextEra Energy	7.2	0.8	—
Total wind power purchased	$62.0	$49.5	$36.7

OG&E Long-Term Service Agreement Commitments

OG&E has a long-term parts and service maintenance contract for the upkeep of the McClain Plant. The existing contract will expire on January 1, 2015. In May 2013, a new contract was signed that is expected to run for the earlier of 128,000 factored-fired hours or 3,600 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2030. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

OG&E has a long-term parts and service maintenance contract for the upkeep of the Redbud Plant. In March 2013, the contract was amended to extend the contract coverage for an additional 24,000 factored-fired hours resulting in a maximum of the earlier of 144,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2031. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

Enogex Energy Resources LLC Commitments

As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company has no obligations included in its Consolidated Financial Statements at December 31, 2013 under OGE Holdings' noncancellable lease obligations previously disclosed in the Company's 2012 Form 10-K.

OG&E Wind Energy Purchased Power Lawsuit

In 2009, OG&E entered into a wind energy purchase power agreement with CPV Keenan for the purchase of all the energy output from its 150 MW wind farm in Woodward County, Oklahoma. In August of 2013, CPV Keenan filed suit against OG&E for the non-payment of curtailment charges. In December 2013, the Company settled its current case with CPV Keenan and recorded additional purchased power expense of $4.3 million, which will be recovered through the fuel adjustment clause.

Enable Gas Transportation and Storage Agreement

OG&E contracts with Enable for gas transportation and storage services. The stated term of this contract expired April 30, 2009, but remained in effect from year-to-year thereafter. On January 31, 2014, in anticipation of entering into a new, five-year contract, OG&E provided written notice of termination of the contract, effective April 30, 2014. Negotiations regarding the new contract are ongoing, and there can be no assurance that the new contract will be agreed upon, or if agreed upon, that the terms of the new contract will be as favorable to us as the expiring contract.

Environmental Laws and Regulations

The activities of OG&E are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection relating to air quality, water quality, waste management, wildlife conservation and natural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate environmental issues that may be caused by its operations or that are attributable to former operators, requiring changes in operations and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

OG&E is managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E is unable to predict the financial impact of these matters with certainty at this time. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of the Company's environmental matters.

Federal Clean Air Act New Source Review Litigation

As previously reported, in July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards.

In March 2013, the DOJ informed OG&E that it was prepared to initiate enforcement litigation concerning the matters identified in the notice of violation. OG&E subsequently met with EPA and DOJ representatives regarding the notice of violation and proposals for resolving the matter without litigation. On July 8, 2013, the United States, at the request of the EPA, filed a complaint for declaratory relief against OG&E in United States District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Federal Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. This complaint seeks to have OG&E submit a new assessment of whether the projects were likely to result in a significant emissions increase. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. OG&E expects to vigorously defend against these claims, but OG&E cannot predict the outcome of such litigation. On August 12, 2013, the Sierra Club filed a complaint against OG&E in the United States District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act.

If OG&E does not prevail in these proceedings and if a new assessment of the projects were to conclude that they caused a significant emissions increase, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.0 billion and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant. OG&E cannot predict at this time whether it will be legally required to incur any of these costs.

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Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated above, in Note 16 below, in Item 3 of Part I and under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

16. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2013, 85 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and seven percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of OGE Energy and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

Crossroads Wind Farm

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 megawatts of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind farm. Also as part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for the Crossroads wind farm which allowed the Crossroads wind farm to interconnect at 227.5 megawatts. On August 31, 2012, OG&E filed an application with the APSC requesting approval to recover the Arkansas portion of the costs of the Crossroads wind farm through a rider until such costs are included in OG&E's base rates as part of its next general rate proceeding. On April 15, 2013, the APSC issued an order authorizing OG&E to recover the Arkansas portion of the cost to construct the Crossroads wind farm, effective retroactively to August 1, 2012. The costs are being recovered through the Energy Cost Recovery Rider.

Fuel Adjustment Clause Review for Calendar Year 2011

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On July 31, 2012, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2011 fuel adjustment clause and for a prudence review of OG&E's electric generation, purchased power and fuel procurement processes and costs in calendar year 2011. OG&E filed information and documents in response to the OCC's application on October 1, 2012. On December 19, 2012, witnesses for the OCC Staff filed responsive testimony recommending that the OCC approve OG&E's fuel adjustment clause costs and recoveries for the calendar year 2011 and recommending that the OCC find that OG&E's electric generation, purchased power, fuel procurement and other fuel related practices, policies and decisions during calendar year 2011 were fair, just and reasonable and prudent. On April 9, 2013, the OCC administrative law judge recommended that the OCC find that for the calendar year 2011 OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent. On June 18, 2013, the OCC issued an order approving the administrative law judge’s recommendation.

Pending Regulatory Matters

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any Federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma. These changes to the "right of first refusal" apply only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which were filed on November 13, 2012. On May 29, 2013, the Governor signed House Bill 1932 into law which establishes a right of first refusal for Oklahoma incumbent transmission owners, including OG&E, to build new transmission projects with voltages under 300 kilovolts that interconnect to those incumbent entities' existing facilities. OG&E believes this law is consistent with the language of Order No. 1000.

On July 18, 2013, the FERC issued an order on the SPP's Order No. 1000 compliance filing. This order accepted in part and rejected in part the SPP's plan for complying with Order No. 1000. The FERC rejected the SPP's plan to retain the right of first refusal for projects that would operate between 100 kilovolts and 300 kilovolts. However, the FERC clarified that a right of first refusal was appropriate in certain circumstances. It is not clear how the FERC's order will relate to the recently enacted Oklahoma law addressing a right of first refusal for lower voltages. On November 15, 2013, SPP made its FERC compliance filing, as required by the July 18, 2013 order. The SPP changes to its tariff and Membership Agreement included provisions that (i) clarify that facilities between 100 kilovolts and 300 kilovolts would be subject to the competitive selection process, (ii) only allow certain evidence, such as state laws (like House Bill 1932) and the holders of existing rights of way, to be considered during the competitive selection process and not earlier in the process; (iii) apply a right of first refusal to transmission projects needed for reliability within three years in certain situations; and (iv) revise the tariff’s competitive selection process, including changes to the criteria for identifying qualifying transmission owners, the requirements for submission of information by transmission owners seeking to participate in competitive selections, and the procedures that govern the competitive selection process.

OGE Energy cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. OG&E has filed a petition for review in the D.C. Circuit relating to the same matter. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

Fuel Adjustment Clause Review for Calendar Year 2012

On July 31, 2013, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2012, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 9, 2013. A hearing on this matter is scheduled for April 24, 2014.

Request for Modification to Previous Orders

On August 2, 2013, OG&E filed an application at the OCC seeking to make minor modifications to three previous OCC orders. The purpose of the application was to address the timing of certain requirements contained in those orders. OG&E's application proposed to address these issues in OG&E's next general rate case thus avoiding the cost associated with a rate case filing now and benefiting customers by deferring the recovery of certain costs identified in the previous orders. On September 3, 2013, the PUD Staff filed a motion to dismiss OG&E's application. PUD Staff requested that the OCC dismiss OG&E's application and issue an order requiring OG&E to file a rate case for the 2012 test year.

On September 11, 2013, the PUD Staff withdrew their motion to dismiss OG&E's application and on September 12, 2013, filed an application requesting a public hearing, review and possible adjustment of the rates and charges of OG&E based on the 2012 test year. To date, no procedural schedule has been established for either the OG&E application or the PUD Staff application.

Energy Efficiency Program Filing

On October 9, 2013 OG&E filed an application with the APSC requesting approval of interim modifications to approved Energy Efficiency Programs, new tariff revisions and the waiver of certain provisions of the Commission’s Rules for Conservation and Energy Efficiency Programs.

Market-Based Rate Authority

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rates sales outside of the SPP's energy imbalance service market. On May 2, 2013, the FERC issued an order accepting OG&E's June 2012 triennial market power update.

On December 30, 2013, OG&E submitted to the FERC a market-based rate change in status filing and a revised market-based rate tariff. The revised tariff will authorize OG&E to (i) sell electric energy and capacity at market-based rates without geographic restriction, and (ii) sell ancillary services in the SPP and Midcontinent Independent System Operator, Inc. markets. The primary goal of this filing was to implement the market-based rate authority OG&E needs to fully participate in SPP’s Integrated Marketplace. OG&E requested that FERC issue an order on or before February 28, 2014 that accepts the revised market-based rate tariff to be effective on the date SPP’s Integrated Marketplace goes into operation, which is expected to be March 1, 2014.

Section 206 Complaint

On November 26, 2013, Arkansas Electric Cooperative Corporation filed a complaint at the FERC against OG&E, arguing that the wholesale formula rate contract between OG&E and Arkansas Electric Cooperative Corporation (formerly between OG&E and Arkansas Valley Electric Cooperative) is unjust and unreasonable with respect to several items. After engaging in settlement discussions, OG&E and Arkansas Electric Cooperative Corporation have tentatively agreed to terms of a settlement and are jointly preparing an offer of settlement to be filed with FERC. OG&E believes the reduction in revenue will be less than $1.0 million per year.

17. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

Quarter ended (In millions, except per share data)		March 31	June 30	September 30	December 31	Total
Operating revenues	2013	$901.4	$734.2	$723.2	$508.9	$2,867.7
	2012	$840.7	$855.0	$1,113.4	$862.1	$3,671.2
Operating income	2013	$75.4	$143.9	$260.9	$73.3	$553.5
	2012	$98.3	$177.3	$304.0	$97.3	$676.9
Net income	2013	$28.0	$93.0	$215.2	$57.6	$393.8
	2012	$47.5	$101.6	$192.4	$43.5	$385.0
Net income attributable to OGE Energy	2013	$23.1	$91.7	$215.2	$57.6	$387.6
	2012	$37.1	$93.9	$185.5	$38.5	$355.0
Basic earnings per average common share attributable to OGE Energy common shareholders (A)	2013	$0.12	$0.46	$1.08	$0.29	$1.96
	2012	$0.19	$0.48	$0.94	$0.19	$1.80
Diluted earnings per average common share attributable to OGE Energy common shareholders (A)	2013	$0.12	$0.46	$1.08	$0.29	$1.94
	2012	$0.19	$0.47	$0.94	$0.19	$1.79

(A) Due to the impact of dilution on the earnings per share calculation, quarterly earnings per share amounts may not add to the total.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. We did not audit the consolidated financial statements of Enable Midstream Partners, LP (Enable), a partnership in which the Company has a 28.5 percent interest. The Company’s investment in Enable constituted 14.2 percent of the Company’s assets as of December 31, 2013 (none at December 31, 2012), and the Company’s equity earnings in the net income of Enable constituted 19.4 percent of the Company’s income before income taxes for the year ended December 31, 2013 (none for the years ended December 31, 2012 and 2011). Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Enable, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 25, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 25, 2014

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. The Company has an investment in an unconsolidated affiliate (see Note 3 of Notes to Condensed Consolidated Financial Statements). As the Company does not control this affiliate, its disclosure controls and procedures with respect to such affiliate is more limited than those the Company maintains with respect to its consolidated subsidiaries. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (1992). Based on our assessment, we believe that, as of December 31, 2013, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

/s/ Peter B. Delaney
Peter B. Delaney, Chairman of the Board, President
and Chief Executive Officer

/s/ Scott Forbes
Scott Forbes, Controller
and Chief Accounting Officer

/s/ Sean Trauschke
Sean Trauschke, Vice President
and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2013 of OGE Energy Corp. and our report dated February 25, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 25, 2014

Item 9B. Other Information.
None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

OGE Energy maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on OGE Energy's web site address www.oge.com under the heading "Investor Relations", "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 28, 2014. Such proxy statement is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

(i) The following Consolidated Financial Statements are included in Part II, Item 8 of this Annual Report:

- Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011
- Consolidated Balance Sheets at December 31, 2013 and 2012
- Consolidated Statements of Capitalization at December 31, 2013 and 2012
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2013, 2012 and 2011
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)
- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm (Audit of Internal Control)

(ii) The financial statements of Enable Midstream Partners, LP, required pursuant to Rule 3-09 of Regulation S-X are filed as Exhibit 99.06

2. Financial Statement Schedule (included in Part IV)

- Schedule II - Valuation and Qualifying Accounts

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective Consolidated Financial Statements or Notes thereto.

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3. Exhibits

Exhibit No.	Description
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein)
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.1	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.12	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.13	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.14	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed March 15, 2013 (File No. 1-12579) and incorporated by reference herein).

3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein)

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4.03	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)
4.05	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein)
4.06	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.07	Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.08	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
4.09	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein)
4.10	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein)
4.11	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein)
4.12	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein)
4.13	Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (File No. 1-1097) and incorporated by reference herein)
4.14	Supplemental Indenture No. 13 dated as of May 1, 2013 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 13, 2013 (File No. 1-1097) and incorporated by reference herein)
10.01*	OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)
10.02*	OGE Energy's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.03	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 9, 2012 (File No. 1-12579) and incorporated by reference herein)
10.04	Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.05	Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by

	reference herein)
10.06	Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.07*	Amendment No. 1 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.08	Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.24 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.09*	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

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10.10	Credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.11	Credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.12*	Amendment No. 1 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.13*	Amendment No. 2 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.14	Ownership and Operating Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
10.15*	OGE Energy Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.16*	OGE Energy Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.17*	OGE Energy Deferred Compensation Plan, as amended and restated. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.18*	Amendment No. 3 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.06 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.19*	Amendment No. 2 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.20*	OGE Energy's 2008 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.21*	OGE Energy's 2008 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.22*	Form of Employment Agreement for all existing and future officers of the Company relating to change of control. (Filed as Exhibit 10.28 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.23*	Form of Restricted Stock Agreement under OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.24	Agreement, dated February 17, 2010, between OG&E and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein)

10.25*	Amendment No. 1 to OGE Energy's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.26*	Amendment No. 1 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.27	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.28	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.29	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.30	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed June 28, 2011 (File No. 1-12579) and incorporated by reference herein)
10.31*	Amendment No. 2 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.41 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)

10.32*	Amendment No. 3 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.39 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.33*	Amendment No. 1 to OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.34*	Director Compensation.
10.35*	Executive Officer Compensation.
10.36	First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of May 1, 2013 (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.37	Amended and Restated Limited Liability Company Agreement of CNP OGE GP LLC dated as of May 1, 2013 (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.38	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC (Filed as Exhibit 10.03 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.39	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP (Filed as Exhibit 10.04 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.40*	OGE Energy's 2013 Stock Incentive Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.41*	OGE Energy's 2013 Annual Incentive Compensation Plan. (Filed as Annex C to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.42	Letter of extension dated as of July 29, 2013 for the Company's credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein)
10.43	Letter of extension dated as of July 29, 2013 for OG&E's credit agreement dated as of December 13,2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein)
10.44*	Amendment No. 4 to the Company's Deferred Compensation Plan (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.45*	OGE Energy Corp. Involuntary Severance Benefits Plans for Non-Officers (Applicable only to non-officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.46*	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (Applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.47*	Retention Agreement effective as of October 24, 2013, by and between OGE Enogex Holdings, LLC and E. Keith Mitchell (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q filed November 6, 2013 (File No.

	1-12579) and incorporated by reference herein)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
23.02	Consent of Deloitte & Touche LLP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

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99.02	Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 22, 2011 (File No. 1-12579) and incorporated by reference herein)
99.03	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein)
99.04	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
99.05	Description of Capital Stock. (Filed as Exhibit 99.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein)
99.06	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2013
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Deductions (A)	Balance at End of Period
(In millions)				
Balance at December 31, 2011				
Reserve for Uncollectible Accounts	$1.9	$5.8	$3.9	$3.8
Balance at December 31, 2012				
Reserve for Uncollectible Accounts	$3.8	$3.3	$4.5	$2.6
Balance at December 31, 2013				
Reserve for Uncollectible Accounts	$2.6	$2.5	$3.2	$1.9

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 25th day of February, 2014.

OGE ENERGY CORP.
(Registrant)

By /s/ Peter B. Delaney
Peter B. Delaney
Chairman of the Board,
President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Peter B. Delaney Peter B. Delaney	Principal Executive Officer and Director;	February 25, 2014
/s/ Sean Trauschke Sean Trauschke	Principal Financial Officer; and	February 25, 2014
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 25, 2014
James H. Brandi	Director;	
Wayne H. Brunetti	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
Kirk Humphreys	Director;	
Robert Kelley	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
Leroy C. Richie	Director. and	
Sheila G. Talton	Director	
/s/ Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 25, 2014