2012 ANNUAL REPORT

NEW JERSEY NATURAL GAS

2012 ANNUAL REPORT

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
New Jersey Natural Gas Company

We have audited the accompanying balance sheets of New Jersey Natural Gas Company (the "Company") (a wholly owned subsidiary of New Jersey Resources Corporation) as of September 30, 2012 and 2011, and the related statements of operations, common stock equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of New Jersey Natural Gas Company as of September 30, 2012 and 2011, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

December 20, 2012

New Jersey Natural Gas Company

STATEMENTS OF OPERATIONS

(Thousands)

Fiscal years ended September 30,	**2012**	2011
OPERATING REVENUES	**$ 627,713**	$ 971,724
OPERATING EXPENSES		
Gas purchases	**274,370**	592,909
Operation and maintenance	**111,998**	108,800
Regulatory rider expenses	**40,350**	51,246
Depreciation and amortization	**35,247**	33,140
Energy and other taxes	**41,140**	62,464
Total operating expenses	**503,105**	848,559
OPERATING INCOME	**124,608**	123,165
Other income	**1,655**	3,354
Interest charges, net of capitalized interest	**14,890**	14,875
INCOME BEFORE INCOME TAXES	**111,373**	111,644
Income tax provision	**38,135**	40,322
NET INCOME	**$ 73,238**	$ 71,322

See Notes to Financial Statements

New Jersey Natural Gas Company

STATEMENTS OF CASH FLOWS

(Thousands)

Fiscal years ended September 30,	**2012**	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 73,238**	$ 71,322
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization	**35,247**	33,140
Allowance for funds used during construction	**(638)**	(2,100)
Amortization of deferred charges	**726**	734
Allowance for bad debt expense	**2,334**	4,697
Deferred income taxes	**23,276**	9,046
Manufactured gas plant remediation costs	**(7,965)**	(14,115)
Cost of removal – asset retirement obligation	**(1,196)**	(826)
Contributions to postemployment benefit plans	**(25,775)**	(6,480)
Changes in:		
Components of working capital	**(47,624)**	39,795
Other noncurrent assets	**(14,679)**	10,473
Other noncurrent liabilities	**21,311**	8,173
Cash flows from operating activities	**58,255**	153,859
CASH FLOWS (USED IN) INVESTING ACTIVITIES		
Expenditures for		
Utility plant	**(104,277)**	(93,624)
Cost of removal	**(12,178)**	(8,369)
Withdrawal from (investment in) restricted cash construction fund	**(802)**	58
Cash flows (used in) investing activities	**(117,257)**	(101,935)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES		
Payments of common stock dividends to parent	**(47,328)**	(44,641)
Tax benefit from stock options exercised	**73**	367
Refinancing of long-term debt	**—**	97,045
Payments of long-term debt	**(8,025)**	(130,091)
Proceeds from short-term debt, net of payments	**108,500**	19,500
Proceeds from sale-leaseback transaction	**6,522**	5,901
Cash flows from (used in) financing activities	**59,742**	(51,919)
Change in cash and cash equivalents	**740**	5
Cash and cash equivalents at beginning of period	**5**	—
Cash and cash equivalents at end of period	**$ 745**	$ 5
CHANGES IN COMPONENTS OF WORKING CAPITAL		
Receivables	**$ 10,174**	$ (30,187)
Inventories	**13,511**	20,770
Recovery of gas costs	**(11,686)**	41,118
Accounts payable and other	**6,277**	(2,777)
Gas purchases payable	**(7,848)**	(14,098)
Prepaid and accrued taxes, net	**14,920**	(9,565)
Customers' credit balances and deposits	**(65,254)**	21,801
Restricted broker margin accounts	**10,009**	7,519
Other current assets	**(17,727)**	5,214
Total	**$ (47,624)**	$ 39,795
SUPPLEMENTAL DISCLOSURES OF CASH FLOWS INFORMATION		
Cash paid for		
Interest (net of amounts capitalized)	**$ 12,407**	$ 13,301
Income taxes	**$ 8,179**	$ 27,402
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING ACTIVITIES		
Accrued Capital Expenditures	**$ (2,392)**	$ 5,731

See Notes to Financial Statements

New Jersey Natural Gas Company

BALANCE SHEETS

ASSETS

(Thousands) September 30,	**2012**	2011
PROPERTY, PLANT AND EQUIPMENT		
Utility plant, at cost	**$ 1,591,532**	$ 1,502,451
Construction work in progress	**102,420**	92,827
	1,693,952	1,595,278
Accumulated depreciation and amortization	**(402,308)**	(397,267)
Property, plant and equipment, net	**1,291,644**	1,198,011
CURRENT ASSETS		
Cash and cash equivalents	**745**	5
Customer accounts receivable:		
Billed	**33,093**	45,092
Unbilled	**7,017**	7,333
Allowance for doubtful accounts	**(4,665)**	(4,472)
Regulatory assets	**32,734**	17,630
Gas in storage, at average cost	**145,379**	159,328
Materials and supplies, at average cost	**6,561**	6,123
Prepaid taxes	**25,515**	39,827
Derivatives, at fair value	**6,203**	5,424
Broker margin account	**1,713**	11,722
Deferred taxes	**—**	14,878
Other	**7,730**	6,501
Total current assets	**262,025**	309,391
NONCURRENT ASSETS		
Regulatory assets	**441,263**	434,185
Derivatives, at fair value	**1,000**	2
Other	**9,588**	9,163
Total noncurrent assets	**451,851**	443,350
Total assets	**$ 2,005,520**	$ 1,950,752

See Notes to Financial Statements

New Jersey Natural Gas Company

CAPITALIZATION AND LIABILITIES

(Thousands, except for share data)		
September 30,	**2012**	2011
CAPITALIZATION		
Common stock, $5 par value; authorized 4,750,000 shares; outstanding 3,214,923 shares	**$ 16,075**	$ 16,075
Premium on common stock	**11,269**	11,269
Contribution from parent and other	**359,047**	358,974
Retained earnings	**287,603**	261,693
Common stock equity	**673,994**	648,011
Long-term debt	**375,169**	376,797
Total capitalization	**1,049,163**	1,024,808
CURRENT LIABILITIES		
Current maturities of long-term debt	**7,760**	7,575
Short-term debt	**135,000**	26,500
Gas purchases payable	**24,480**	32,328
Accounts payable and other	**38,046**	37,650
Deferred and accrued taxes	**1,101**	—
Regulatory liabilities	**1,169**	4,633
New Jersey clean energy program	**5,619**	15,011
Derivatives, at fair value	**5,034**	13,258
Customers' credit balances and deposits	**48,368**	113,622
Total current liabilities	**266,577**	250,577
NONCURRENT LIABILITIES		
Deferred income taxes	**310,452**	302,764
Deferred investment tax credits	**5,905**	6,227
Derivatives, at fair value	—	620
Manufactured gas plant remediation	**182,000**	182,900
Postemployment benefit liability	**91,530**	86,750
Regulatory liabilities	**67,077**	59,837
New Jersey clean energy program	—	5,133
Asset retirement obligation	**27,983**	27,026
Other	**4,833**	4,110
Total noncurrent liabilities	**689,780**	675,367
Total capitalization and liabilities	**$ 2,005,520**	$ 1,950,752

See Notes to Financial Statements

New Jersey Natural Gas Company

STATEMENTS OF COMMON STOCK EQUITY

(Thousands)	Number of Shares	Common Stock	Premium on Common Stock	Contribution from Parent and Other	Retained Earnings	Total
Balance at September 30, 2010	3,215	$ 16,075	$ 11,269	$ 358,607	$ 235,012	$ 620,963
Net income					71,322	71,322
Tax benefit from stock plans				367		367
Cash dividend declared					(44,641)	(44,641)
Balance at September 30, 2011	3,215	16,075	11,269	358,974	261,693	648,011
Net income					**73,238**	**73,238**
Tax benefit from stock plans				**73**		**73**
Cash dividend declared					**(47,328)**	**(47,328)**
Balance at September 30, 2012	**3,215**	**$ 16,075**	**$ 11,269**	**$ 359,047**	**$ 287,603**	**$ 673,994**

See Notes to Financial Statements

1. NATURE OF THE BUSINESS

New Jersey Natural Gas (the Company) is a local natural gas distribution company that provides regulated retail natural gas service to approximately 500,100 residential and commercial customers in central and northern New Jersey, and participates in the off-system sales and capacity release markets. The Company is the regulated utility subsidiary of New Jersey Resources Corporation (NJR) and is subject to rate regulation by the New Jersey Board of Public Utilities (BPU). The Company owns approximately 6,860 miles of distribution main, 6,810 miles of service main, 228 miles of transmission main and approximately 519,000 meters. Additionally, the Company owns and operates two LNG storage plants in Stafford Township, Ocean County, and Howell Township, Monmouth County with an aggregate estimated maximum capacity of approximately 170,000 dths per day and four service centers located in Rockaway Township, Morris County; Atlantic Highlands and Wall Township, Monmouth County; and Lakewood, Ocean County.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulatory Assets & Liabilities

Under cost-based regulation, regulated utility enterprises generally are permitted to recover their operating expenses and earn a reasonable rate of return on their utility investment.

The Company maintains its accounts in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts as prescribed by the BPU and in accordance with the *Regulated Operations* Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). As a result of the impact of the ratemaking process and regulatory actions of the BPU, the Company is required to recognize the economic effects of rate regulation. Accordingly, the Company capitalizes or defers certain costs that are expected to be recovered from its customers as regulatory assets and recognizes certain obligations representing probable future expenditures as regulatory liabilities in the Balance Sheets. See *Note 3. Regulation,* for a more detailed description of the Company's regulatory assets and liabilities.

Gas in Storage

Gas in storage is reflected at average cost in the Balance Sheets, and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business. The Company had 22.2 billion cubic feet (Bcf) and 23.1 Bcf of gas in storage as of September 30, 2012 and 2011, respectively.

Demand Fees

For the purpose of securing adequate storage and pipeline capacity, the Company enters into storage and pipeline capacity contracts, which require the payment of certain demand charges to maintain the ability to access such natural gas storage or pipeline capacity, during a fixed time period, which generally ranges from one to five years. Demand charges are based on established rates as regulated by FERC. These demand charges represent commitments to pay storage providers or pipeline companies for the right to store and transport natural gas utilizing their respective assets. Demand fees of $86.7 million and $98.9 million for fiscal years ended September 30, 2012 and 2011, respectively, which are net of fees received for capacity release, are included in its weighted average cost of gas. The demand charges are expensed as a component of gas purchases in the Statements of Operations based on Basic Gas Supply Service (BGSS) sales and recovered as part of its wholesale gas commodity component of its BGSS tariff.

Derivative Instruments

Derivative instruments associated with natural gas commodity contracts are recorded in accordance with the *Derivatives and Hedging* Topic of the ASC, under which the Company records the fair value of derivatives, held as assets and liabilities. The Company's derivatives used to economically hedge its natural gas purchasing activities are recoverable through its BGSS, a component of its tariff. Accordingly, the offset to the change in fair value of these derivatives is recorded as a Regulatory asset or liability in the Balance Sheets.

See *Note 4. Derivative Instruments* for additional details regarding natural gas transacting activities.

Fair values of exchange-traded instruments, including futures, swaps and certain options, are based on actively quoted market prices. Fair values are subject to change in the near term and reflect management's best estimate based on various factors. In establishing the fair value of commodity contracts that do not have quoted prices, such as physical contracts, and over-the-counter options and swaps, and certain embedded derivatives, management uses available market data and pricing models to estimate fair values. Estimating fair values of instruments that do not have quoted market prices requires management's judgment in determining amounts, which could reasonably be expected to be received from, or paid to, a third party in settlement of the instruments. These amounts could be materially different from amounts that might be realized in an actual sale transaction.

Revenues

Revenues from the sale of natural gas to customers of the Company are recognized in the period that gas is delivered and consumed by customers, including an estimate for unbilled revenue.

In determining the amount of revenue from sales to natural gas customers by the Company, certain assumptions are used to develop estimates of unaccounted-for gas. Unaccounted-for gas occurs for a number of reasons including leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants. The estimating factors may change from time to time as a result of improvements in the quality and/or the timeliness of certain metering and billing information.

The Company records unbilled revenue for natural gas services. Natural gas sales to individual customers are based on meter readings, which are performed on a systematic basis throughout the month. At the end of each month, the amount of natural gas delivered to each customer after the last meter reading is estimated, and the Company recognizes unbilled revenues related to these amounts. The unbilled revenue estimates are based on monthly send-out amounts, estimated customer usage by customer type, weather effects, unaccounted-for gas and the most current tariff rates.

Gas Purchases

The Company's tariff includes a component for BGSS, which is designed to allow the Company to recover the cost of natural gas through rates charged to its customers and is normally revised on an annual basis. As part of computing its BGSS rate, the Company projects its cost of natural gas, net of supplier refunds, the impact of hedging activities and credits from non-firm sales and transportation activities. The Company subsequently recovers or refunds the difference, if any, of actual costs compared with those included in current rates. Any underrecoveries or overrecoveries are either refunded to customers or deferred and, subject to BPU approval, reflected in the BGSS rates in subsequent years.

Income Taxes

The Company computes income taxes using the liability method, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. See *Note 9. Income Taxes.*

Investment tax credits (ITCs) have been deferred and are being amortized as a reduction to the tax provision over the average lives of the related equipment in accordance with regulatory treatment.

Capitalized and Deferred Interest

Included in the Balance Sheets are capitalized amounts associated with the debt and equity components of the Company's allowance for funds used during construction (AFUDC), which are recorded in utility plant. The Company's base rates include the ability for the Company to recover the cost of debt associated with AFUDC and construction work in progress (CWIP). An incremental cost of equity is also recoverable during periods when the Company's short-term debt balances are lower than its CWIP. Corresponding amounts recognized in interest expense and other income, as appropriate, are included in the Statements of Operations are as follows:

	September 30,	
($ in thousands)	**2012**	2011
AFUDC:		
Debt	**$ 300**	$ 1,020
Equity	**638**	2,100
Total capitalized costs	**$ 938**	$ 3,120
Weighted average rate	**1.47%**	5.21%

Pursuant to a BPU order, the Company is permitted to recover carrying costs on uncollected balances related to Societal Benefits Clause (SBC) program costs, which include New Jersey Clean Energy Program (NJCEP), Remediation Adjustment (RA) and Universal Service Fund (USF) expenditures. See *Note 3. Regulation*. Accordingly, other income included $878,000 and $1.1 million for the fiscal years ended September 30, 2012 and 2011, respectively.

Sales Tax Accounting

Sales tax and Transitional Energy Facilities Assessment (TEFA) are collected from customers and presented in both operating revenues and operating expenses on the Statements of Operations as follows:

	September 30,	
(Millions)	**2012**	2011
Sales Tax	**$ 31.3**	$ 49.5
TEFA (1)	**6.0**	9.0
Total	**$ 37.3**	$ 58.5

(1) TEFA will be phased out over a three-year period commencing January 1, 2012.

Cash and Cash Equivalents

Cash and cash equivalents consists of cash on deposit and temporary investments with original maturities

of three months or less, and excludes restricted cash of $1.2 million and $387,000 as of September 30, 2012 and 2011, respectively, that is recorded in other noncurrent assets on the Balance Sheets.

Property Plant and Equipment

Regulated property, plant and equipment are stated at original cost. Costs include direct labor, materials and third-party construction contractor costs, AFUDC and certain indirect costs related to equipment and employees engaged in construction. Upon retirement, the cost of depreciable regulated property, plus removal costs less salvage, is charged to accumulated depreciation with no gain or loss recorded.

Depreciation is computed on a straight-line basis over the useful life of the assets for financial statement purposes and using rates based on the estimated average lives of the various classes of depreciable property for the Company. The composite rate of depreciation used was 2.38 percent of average depreciable property in fiscal 2012 and 2.39 percent in fiscal 2011.

Property, plant and equipment was comprised of the following as of September 30, 2012 and 2011:

(Thousands)

Property Classifications	**Estimated Useful Lives**	**2012**	2011
Distribution Facilities	38 to 74 years	**$ 1,352,101**	$ 1,304,182
Transmission Facilities	35 to 56 years	**248,774**	200,051
Storage Facilities	34 to 47 years	**41,663**	42,364
All other property	5 to 35 years	**51,414**	48,681
Total property, plant and equipment		**1,693,952**	1,595,278
Accumulated depreciation and amortization		**(402,308)**	(397,267)
Property, plant and equipment, net		**$ 1,291,644**	$ 1,198,011

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amount may not be recoverable.

For the fiscal years ended September 30, 2012 and 2011, no impairment was identified.

Customer Accounts Receivable and Allowance for Doubtful Accounts

The Company's receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. The Company evaluates its accounts receivable and, to the extent customer account balances are outstanding for more than thirty days, establishes an allowance for doubtful accounts. The allowance is based on a combination of factors including historical collection experience and trends, aging of receivables, general economic conditions in the company's distribution or sales territories, and customer specific information. Customer accounts are written-off once they are deemed uncollectible.

Asset Retirement Obligations (ARO)

The Company recognizes a liability for its AROs based on the fair value of the liability when incurred, which is generally upon acquisition, construction, development and/or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. In periods subsequent to the initial measurement, the Company is required to recognize changes in the liability resulting from the passage of time (accretion) or due to revisions to either timing or the amount of the originally estimated cash flows to settle the ARO.

Pension and Postemployment Plans

The Company has two noncontributory defined pension plans covering substantially all employees, including officers. Benefits are based on each employee's years of service and compensation. The Company's funding policy is to contribute annually to these plans at least the minimum amount required under the Employee Retirement Income Security Act (ERISA) of 1974, as amended, and not more than can be deducted for federal income tax purposes. Plan assets consist of equity securities, fixed-income securities and short-term investments. In fiscal 2012 and 2011, the Company had no minimum funding requirements however the Company made discretionary contributions to the pension plans of $20 million in both December 2012 and 2011.

The Company also provides two primarily noncontributory medical and life insurance plans for eligible retirees and dependents. Medical benefits, which make up the largest component of the plans, are based upon an age and years-of-service vesting schedule and other plan provisions. Funding of these benefits is made primarily into Voluntary Employee Beneficiary Association trust funds. The Company contributed $5.8 million and $6.5 million in aggregate to these plans in fiscal 2012 and 2011, respectively.

Recent Updates to the Accounting Standards Codification (ASC)

Fair Value

In May 2011, the FASB issued an amendment to ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifying certain guidance to ensure that U.S. generally accepted accounting principles (U.S. GAAP) and International Financial Reporting Standards (IFRS) have the same fair value meaning, measurements and disclosure requirements. The amended guidance became effective for interim and annual periods beginning after December 15, 2011. There was no impact to the Company's financial position, results of operations or cash flows upon adoption.

Balance Sheet Offsetting

In December 2011, the FASB issued an amendment to ASC Topic 210, *Balance Sheet*, requiring additional disclosures about the nature of an entity's rights of setoff and related master netting arrangements associated with its financial and derivative instruments. The objective of the disclosures is to facilitate comparison between financial statements prepared on the basis of U.S. GAAP and those prepared on the basis of IFRS. The amended guidance will become effective for interim and annual periods beginning on or after January 1, 2013, and will be applied retrospectively. The Company has determined that the new guidance will not impact its financial position, results of operations or cash flows upon adoption.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure of contingencies during the reporting period. On a monthly basis, the Company evaluates its estimates, including those related to the calculation of the fair value of derivative instruments, unbilled revenues, allowance for doubtful accounts, provisions for depreciation and amortization, regulatory assets and liabilities, income taxes, pensions and other postemployment benefits, contingencies related to environmental matters and litigation and asset retirement obligations, which are evaluated on an annual basis. The Company bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources.

The Company has legal, regulatory and environmental proceedings during the normal course of business which can result in loss contingencies. When evaluating the potential for a loss, the Company will establish a reserve if a loss is probable and can be estimated, in which case it is the Company's policy to accrue the full amount of such estimate. Where the information is sufficient only to establish a range of probable liability, and no point within the range is more likely than any other, it is the Company's policy to accrue the lower end of the range. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from estimates.

Subsequent Events

In October 2012, high winds, heavy rainfall and the related flooding associated with Post Tropical Cyclone Sandy, commonly referred to as Superstorm Sandy (Superstorm Sandy), caused significant damage to portions of the Company's distribution infrastructure. As a result, the Company shut off its natural gas infrastructure in certain areas of its service territory that were most heavily damaged, affecting approximately 30,100 of the Company's approximately 500,100 customers.

We anticipate that Superstorm Sandy and its aftermath will influence our financial results but are still assessing the damages. The Company is unable to estimate the possible loss or range of loss related to Superstorm Sandy, however, such costs could be material. The financial effects can include lower operating revenues, lower utility gross margin due to extended outages and inability to bill and collect revenues, and higher capital expenditures related to the restoration, repair or replacement of damaged equipment and assets. On November 19, 2012, the Company filed a petition with the BPU requesting deferral accounting for actually incurred uninsured incremental operating and maintenance costs associated with Superstorm Sandy. In addition, the Company requested the review of and the appropriate amortization period for such deferred expenses be addressed in the Company's next base rate case. However, there can be no assurances that such recovery mechanisms will be available or, if available, no assurances can be given relative to the timing or amount of such recovery.

While the Company believes it has sufficient liquidity to meet its current obligations and to begin to fund restoration efforts from a combination of cash-on-hand and available capacity under revolving credit facilities, the Company may need to seek additional financing in order to fully fund restoration efforts.

To the best of our knowledge and belief, no other material events have occurred subsequent to September 30, 2012, but before December 20, 2012, the date the financial statements were issued that require consideration as adjustments to or disclosures in the aforementioned financial statements, except as disclosed in *Note 3. Regulation* and *Note 7. Employee Benefit Plans*.

3. REGULATION

The Electric Discount and Energy Competition Act (EDECA) is the legal framework for New Jersey's public utility and wholesale energy landscape. The Company is required, pursuant to a written order by the BPU under EDECA, to open its residential markets to competition from third-party natural gas suppliers. Customers can choose the supplier of their natural gas commodity in the Company's service territory.

As required by EDECA, the Company's rates are segregated into two primary components, the commodity portion, which represents the wholesale cost of natural gas, including the cost for interstate pipeline capacity to transport the gas to the Company's service territory, and the delivery portion, which represents the transportation of the commodity portion through the Company's gas distribution system to the end-use customer. The Company does not earn utility gross margin, which is defined as natural gas revenues less natural gas purchases, sales tax, a Transitional Energy Facilities Assessment (TEFA) and regulatory rider expenses, on the commodity portion of its natural gas sales. The Company earns utility gross margin through the delivery of natural gas to its customers, regardless of whether it or a third-party supplier provides the wholesale natural gas commodity.

Under EDECA, the BPU is required to audit the state's energy utilities every two years. The primary purpose of the audit is to ensure that utilities and their affiliates offering unregulated retail services do not have unfair competitive advantage over nonaffiliated providers of similar retail services. A combined competitive services and management audit of the Company commenced in November 2006, and a final report on findings and recommendations was approved by the BPU on January 28, 2009. As of September 30, 2011, all recommendations have been implemented by the Company and a completion letter was received from the BPU on October 24, 2011, that finalized the audit.

The Company is subject to cost-based regulation, therefore, it is permitted to recover authorized operating expenses and earn a reasonable return on its utility investment based on the BPU's approval, in accordance with accounting guidance applicable to regulated operations. The impact of the ratemaking process and decisions authorized by the BPU allows the Company to capitalize or defer certain costs that are expected to be recovered from its customers as regulatory assets and to recognize certain obligations representing amounts that are probable future expenditures as regulatory liabilities.

As recovery of regulatory assets is subject to BPU approval, if there are any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to income in the period of such determination.

Regulatory assets and liabilities included on the Balance Sheets as of September 30, are comprised of the following:

(Thousands)	**2012**	2011
Regulatory assets-current		
Underrecovered gas costs	**$ 7,053**	$ —
Conservation Incentive Program	**25,681**	9,178
Derivatives, net	**—**	8,452
Total current	**$ 32,734**	$ 17,630
Regulatory assets-noncurrent		
Environmental remediation costs		
Expended, net of recoveries	**$ 59,745**	$ 75,646
Liability for future expenditures	**182,000**	182,900
Deferred income and other taxes	**11,405**	10,879
Energy Efficiency Program	**26,025**	11,906
New Jersey Clean Energy Program	**5,619**	20,144
Postemployment and other benefit costs	**142,495**	123,827
Other	**13,974**	8,883
Total noncurrent	**$ 441,263**	$ 434,185
Regulatory liability-current		
Overrecovered gas costs	**$ —**	$ 4,633
Derivatives, net	**1,169**	—
Total current	**$ 1,169**	$ 4,633
Regulatory liabilities-noncurrent		
Cost of removal obligation	**$ 65,994**	$ 59,752
Derivatives, net	**1,000**	—
Other	**83**	85
Total noncurrent	**$ 67,077**	$ 59,837

The Company's recovery of costs is facilitated through its base rates, BGSS and other regulatory riders. The Company is required to make an annual filing to the BPU by June 1 of each year for review of its BGSS, Conservation Incentive Program (CIP) and various other programs and related rates. Annual rate changes are requested to be effective at the beginning of the following fiscal year. In addition, the Company is also permitted to request approval of certain rate or program changes on an interim basis. All rate and program changes are subject to proper notification, and BPU review and approval.

Gas Costs

The Company recovers its cost of gas through the BGSS rate component of its customers' bills. The Company's cost of gas includes the purchased cost of the natural gas commodity, fees paid to pipelines and storage facilities, adjustments as a result of BGSS incentive programs, and hedging transactions. Under-recovered gas costs represent a regulatory asset that generally occurs during periods when the Company's BGSS rates are lower than actual costs and requests amounts to be recovered from customers in the future. Conversely, over-recovered gas costs represent a regulatory liability that generally occurs when the Company's BGSS rates are higher than actual costs and requests approval to be returned to customers including interest, when applicable, in accordance with the Company's approved tariff.

Conservation Incentive Program

The CIP permits the Company to recover utility gross margin variations related to customer usage resulting from customer conservation efforts and allows the Company to mitigate the impact of weather on its gross margin. Such utility gross margin variations are recovered in the year following the end of the CIP usage year, without interest, and are subject to additional conditions, including an earnings test and an evaluation of BGSS related savings.

Derivatives

Derivatives are utilized by the Company to manage the price risk associated with its natural gas purchasing activities and to participate in certain BGSS incentive programs. The gains and losses associated with the Company's derivatives are recoverable through its BGSS, as noted above, without interest. See *Note 4. Derivatives*.

Environmental Remediation Costs Recovery

The Company is responsible for the cleanup of certain former gas manufacturing facilities. Actual expenditures are recovered, with interest, over seven year rolling periods, through a RA rate rider. Recovery for the Company's estimated future liability will be requested and/or recovered when actual expenditures are incurred. See *Note 10. Commitments and Contingent Liabilities*.

Deferred Income Taxes

In 1993, the Company adopted the provisions of ASC 740, Income Taxes, which changed the method used to determine deferred tax assets and liabilities. Upon adoption, the Company recognized a transition adjustment and corresponding regulatory asset representing the difference between the Company's existing deferred tax amounts compared with the deferred tax amounts calculated in accordance with the change in method prescribed by ASC 740. The Company recovers the regulatory asset associated with these tax impacts through future base rates, without interest.

New Jersey Clean Energy Program (NJCEP)

The NJCEP is a statewide program that encourages energy efficiency and renewable energy. Funding amounts are determined by the BPU and all New Jersey utilities are required to share in the funding obligation. The current NJCEP program is for the calendar years 2009 through 2012. The Company recovers the costs associated with its portion of the NJCEP obligation, including interest, through its Societal Benefits Clause (SBC) rate rider.

Energy Efficiency Program (EE)

The Company administers certain programs that supplement the states' NJCEP and that allows the Company to promote clean energy to its residential and commercial customers, as described further below. The Company will recover related expenditures and a weighted average cost of capital through an EE rate rider, as approved by the BPU, over a four to ten year period depending upon the initiative and available on-bill financing.

Postemployment and Other Benefit Costs

Postemployment and Other Benefit Costs represents the Company's underfunded postemployment benefit obligations that the Company began recognizing in fiscal 2006, as a result of changes in the accounting provisions of ASC 715, Compensation and Benefits, as well as a fiscal 2010 tax charge resulting from a change in the deductibility of federal subsidies associated with Medicare D, both of which are deferred as regulatory assets and are recoverable, without interest, in base rates. See *Note 7. Employee Benefit Plans*.

Other Regulatory Assets

Other regulatory assets consists primarily of deferred costs associated with certain components of the Company's SBC, as discussed further below, and the Company's compliance with federal and state mandated pipeline integrity management (PIM) provisions. The Company's related costs to maintain the operational integrity of its distribution and transmission main are recoverable, subject to BPU review and approval, in its next base rate case. The Company is limited to recording a regulatory asset associated with PIM that does not exceed $700,000 per year. In addition, to the extent that project costs are lower than the approved PIM annual expense of $1.4 million, the Company will record a regulatory liability that will be refundable as a credit to customers' gas costs when the net cumulative liability exceeds $1 million. As of September 30, 2012, the Company has recorded $2.5 million of PIM in other regulatory assets.

Cost of Removal Obligation

The Company accrues and collects for cost of removal in base rates. A regulatory liability represents the current collections in excess of actual expenditures, which the Company will return to customers over approximately 48 years, through a reduction in the depreciation expense component of the Company's base rates, as approved by the BPU in the Company's last base rate case.

The following is a description of regulatory proceedings during fiscal 2011 and 2012:

BGSS and CIP

BGSS rates are normally revised on an annual basis. In addition, in order to manage the fluctuations in wholesale natural gas costs, the Company has the ability to make two interim filings during the fiscal year to increase residential and small commercial customer BGSS rates on a self-implementing and provisional basis. The Company is also permitted to refund or credit back a portion of the commodity costs to customers when the natural gas commodity costs decrease in comparison to amounts projected or to amounts previously collected from customers. During fiscal 2012, the Company provided bill credits of approximately $85.9 million to the Company's residential and small commercial customers due to a decline in the wholesale prices of natural gas and a change in the methodology used to develop estimates of unaccounted-for gas. Commodity prices were relatively stable during fiscal 2011, therefore, there were no refunds or rate adjustments. On March 9, 2012, the Company notified the BPU of a 3.6 percent decrease related to its BGSS rate, effective April 1, 2012, which will have an annual impact of approximately $19 million.

Concurrent with the annual BGSS filing, the Company files for an annual review of its CIP. The CIP was initially approved as a three-year program through September 2009. During fiscal 2010, the BPU approved an extension of the program through September 30, 2013. It is anticipated that the Company will file for an extension of its CIP in fiscal 2013.

The Company's annual BGSS and CIP filings are summarized as follows:

- June 2010 BGSS/CIP filing - In April 2011, the BPU issued their final order approving the Company's request to reduce rates for a 3.5 percent decrease for the average residential heating customer related to the BGSS rate, effective September 16, 2010. This offset the Company's request for an increase in the CIP recovery rate, approved by the BPU effective October 1, 2010, allowing for a total annual recovery of $12.1 million representing CIP amounts accrued and estimated through September 30, 2010.

- June 2011 BGSS/CIP filing - The Company proposed to reduce BGSS rates for a 9.1 percent decrease for the average residential heating customer as a result of cost control and natural gas purchasing strategies, as well as lower natural gas prices. In addition, the Company requested approval to modify its CIP recovery rates resulting in a decrease to the total annual recovery of $3 million. The proposed CIP rates result in an increase to all classes except residential heat, which represents a decrease. In May 2012, the BPU approved the changes effective October 4, 2011.

- June 2012 BGSS/CIP filing - The Company proposed to maintain its current BGSS rate. In addition, the Company requested approval to decrease the CIP rate for residential non-heating customers and increase the CIP rates for residential heating and commercial customers, which were approved on a provisional basis effective October 12, 2012, which increased an average residential heating customer bill by 2.4 percent.

Infrastructure Programs

The Company has significant annual capital expenditures associated with the management of its natural gas distribution and transmission system and its associated pipeline integrity.

During fiscal 2009, the Company implemented its Accelerated Infrastructure Programs (AIP) commencing construction on fourteen infrastructure projects at a BPU approved cost of $70.8 million (AIP I). AIP was initially approved by the BPU as a two-year program, to enhance the reliability of the Company's gas distribution system and to support economic development and job growth in New Jersey. During fiscal 2011, the BPU approved an extension to the Company's AIP, allowing for additional capital investments of $60.2 million (AIP II) to be made through October 31, 2012. The Company defers the costs associated with the AIP projects, including the Company's weighted cost of capital, and upon regulatory approval recovers these investments through its base rates.

Annual filings include the following:

- June 2011 AIP filing - The Company filed for AIP base rate cost recovery, which represented an increase of $4.7 million related to AIP I and AIP II infrastructure investments installed in the Company's distribution and transmission systems. A settlement was reached and approved by the BPU effective October 1, 2011. The rate changes included a weighted average cost of capital of 7.12 percent for AIP II. The existing weighted average cost of capital for AIP I remained the same at 7.76 percent. The requested base rate change was approved on a final basis in August 2012.

- November 2012 AIP filing - The Company filed for AIP base rate cost recovery, requesting an increase of $6.9 million, which represents a cumulative impact of $15.8 million annually, related to AIP I and AIP II infrastructure investments installed in the Company's distribution and

transmission systems through October 31, 2012. The existing weighted average cost of capital remained the same for both AIP I and AIP II. The base rate change is requested to be approved in March 2013.

On March 20, 2012, the Company filed a petition with the BPU seeking to implement a Safety Acceleration and Facility Enhancement (SAFE) program, whereby the Company would invest up to $204 million over a five-year period to replace portions of the Company's gas distribution unprotected steel and cast iron infrastructure in order to improve the safety and reliability of the gas distribution system. The Company entered into a stipulation with the BPU Staff and Rate Counsel, which was approved by the BPU on October 23, 2012, to include a four-year incremental investment program of $130 million, exclusive of AFUDC accruals. The approved SAFE Program will include the deferral of infrastructure costs subject to review in the Company's next base rate case to be filed no later than November 2015, the deferral of depreciation expense on SAFE investments and recognizes an overall rate of return on infrastructure investments of 6.9 percent. The deferred cost recovery will include accruals for both debt and equity components of AFUDC while construction is in progress. When construction is completed and plant is placed in service, the Company will accrue an AFUDC rate at 6.9 percent per year until such time that the Company receives approval for recovery of all costs through base rates.

BGSS Incentive Programs

The Company is eligible to receive financial incentives for reducing BGSS costs through a series of utility gross margin-sharing programs that include off-system sales, capacity release, storage incentive and Financial Risk Management (FRM) programs. In August 2011, the BPU approved an extension of the Company's BGSS incentive programs for four years through October 31, 2015, maintaining the existing margin-sharing percentages. This agreement also permits the Company to annually propose a process to evaluate and discuss alternative incentive programs, should performance of the existing incentives or market conditions warrant re-evaluation.

Energy Efficiency Programs (EE)

The Company commenced its EE programs during fiscal 2009, allowing it to promote energy efficiency to its residential and commercial customers while stimulating state and local economies through the creation of jobs. Depending on the specific initiative, the Company recovers costs associated with the programs over a four to ten-year period to facilitate home energy audits and to provide financing alternatives including rebates and other incentives designed to encourage the installation of high efficiency heating and cooling equipment. In September 2010, the Company received BPU approval for recovery of an additional $9.6 million in energy efficiency investments, effective January 1, 2011, to be recovered over a five to ten-year period, depending on the rebate or financing initiative. The approval allowed for an extension of certain existing initiatives, as well as new or expanded funding incentives for commercial customers. In January 2011, the Company notified the BPU that its proposed solar incentive component was withdrawn. On July 15, 2011, the Company filed a separate EE petition, approved by the BPU in January 2012, to extend its current EE programs through January 18, 2013. As of September 30, 2012, the BPU approved total EE expenditures of $35.3 million, of which, the Company has spent a total of $29.2 million.

The EE program investments and costs are filed with the BPU on an annual basis and include the following:

- June 2011 EE filing - The Company requested that the existing EE rate remain the same through an amended filing on July 15, 2011. On January 18, 2012, the BPU approved an extension of the Company's EE program for one year with an additional $10.4 million of investments in customer incentives and rebates, earning a weighted average cost of capital of 7.1 percent, including a cost of equity of 10.3 percent.

- June 2012 EE filing - On July 9, 2012, the Company filed two petitions with the BPU related to The SAVEGREEN Project® (SAVEGREEN) EE programs. The petitions include the 2012 rate filing, which represents a reconciliation of BPU approved actual costs for EE programs and a petition related to the extension of the Company's EE programs over a four-year program, with modifications to include certain new programs. The Company's petition requests a BPU decision in early 2013. The rate impact will incorporate the existing Savegreen programs and the extension of the new Savegreen programs over a four to ten-year period.

Societal Benefits Clause (SBC)

The SBC is comprised of three primary riders that allow the Company to recover costs associated with USF, which is a permanent statewide program for all natural gas and electric utilities for the benefit of income-eligible customers, manufactured gas plant (MGP) remediation, and the NJCEP. The Company has submitted the following filings to the BPU, which includes a report of program expenditures incurred each program year:

- June 2010 SBC filing - The Company filed an application to maintain the existing MGP factor and NJCEP rate. In November 2011, the Company, the BPU and Rate Counsel executed a stipulation agreeing to maintain the existing MGP and NJCEP rates. On January 18, 2012, the BPU approved the filing, in which the Company requested approval of its MGP remediation expenditures incurred through June 30, 2009, which maintained the expected annual recovery at approximately $20 million. In addition, natural gas utilities in the State of New Jersey collectively filed with the BPU to increase the statewide USF rate to be effective October 1, 2010. Effective November 1, 2010, the BPU approved the recovery of the USF program year budget, resulting in an overall increase to the average monthly bill of a residential heating customer by .03 percent, and the recovery of deferred USF administrative costs.

- June 2011 USF filing - The Company filed to reduce the annual USF recovery rate, which was approved by the BPU, effective November 1, 2011.

- February 2012 SBC filing - The Company filed an application requesting approval of its MGP expenditures incurred through June 30, 2011, which continued its existing overall SBC rate and recovery.

- June 2012 USF filing - The Company filed to reduce the USF recovery rate resulting in a .1 percent decrease for the average residential heating customer. The rate was approved by the BPU effective October 1, 2012.

Other Regulatory Initiatives

On June 18, 2012, the BPU approved a pilot program for the Company to invest up to $10 million to build compressed natural gas vehicle refueling stations in Monmouth, Ocean and Morris counties. The Company intends to begin construction of the stations within one year and submit a cost recovery filing to the BPU in the spring of 2013, requesting a base rate change to be effective in the summer of 2013, earning an overall weighted average cost of capital of 7.1 percent, including a cost of equity of 10.3 percent. A portion of the proceeds from the utilization of the CNG equipment, along with any available federal and state incentives, will be credited back to ratepayers to help offset the cost of this investment.

On November 19, 2012, The Company filed a petition with the BPU requesting deferral accounting for actually incurred uninsured incremental operating and maintenance costs associated with Superstorm Sandy. In addition, the Company requested the review of and the appropriate amortization period for such deferred expenses be addressed in the Company's next base rate case.

4. DERIVATIVE INSTRUMENTS

The Company is subject to commodity price risk due to fluctuations in the market price of natural gas. To manage this risk, the Company enters into a variety of derivative instruments including, but not limited to, futures contracts, physical forward contracts, financial options and swaps to economically hedge the commodity price risk associated with its existing and anticipated commitments to purchase and sell natural gas. Accordingly, all of the financial derivative instruments are recorded at fair value in the Balance Sheets. For a more detailed discussion of the Company's fair value measurement policies and level disclosures associated with derivative instruments, see *Note 5. Fair Value*.

Changes in fair value of the Company's derivative instruments, however, are recorded as a component of regulatory assets or liabilities in the Balance Sheets, as the Company has received regulatory approval to defer and to recover these amounts through future BGSS rates as an increase or decrease to the cost of natural gas in the Company's tariff.

The Company elects normal purchase/normal sale accounting treatment on all physical commodity contracts. These contracts are accounted for on an accrual basis. Accordingly, gains or (losses) are recognized in earnings when the contract settles and the natural gas is delivered.

Fair Value of Derivatives

The following table reflects the fair value of the Company's derivative assets and liabilities recognized in the Balance Sheets as of September 30:

		Fair Value			
		2012		2011	
(Thousands)	Balance Sheet Location	**Asset Derivatives**	**Liability Derivatives**	Asset Derivatives	Liability Derivatives
Financial commodity contracts	Derivatives - current	**$ 6,203**	**$ 5,034**	$ 5,424	$ 13,258
	Derivatives - noncurrent	**1,000**	**—**	2	620
Total fair value of derivatives		**$ 7,203**	**$ 5,034**	$ 5,426	$ 13,878

Losses associated with the Company's financial derivatives totaled $25.3 million and $15.1 million for the fiscal years ended September 30, 2012 and 2011, respectively. These derivatives are part of its risk management activities that relate to its natural gas purchasing activities and BGSS incentive programs. As these transactions are entered into pursuant to and recoverable through regulatory riders, any changes in the value of the Company's financial derivatives are deferred in regulatory assets or liabilities and there is no impact to earnings.

As of September 30, 2012, the Company had the following outstanding long (short) derivatives:

	Volume (Bcf)	
	2012	2011
Futures	**16.1**	23.7
Swaps	**3.4**	(1.8)
Options	—	1.1

Broker Margin

Generally, exchange-traded futures contracts require posted collateral, referred to as margin, usually in the form of cash. The amount of margin required is comprised of a fixed initial amount based on the contract and a variable amount based on market price movements from the initial trade price. The Company's broker margin account balances as of September 30, are as follows:

(Thousands)	Balance Sheet Location	**2012**	2011
Broker margin deposit	Broker margin - Current assets	**$ 1,713**	$ 11,722

Wholesale Credit Risk

The Company is exposed to credit risk as a result of their wholesale marketing activities. As a result of the inherent volatility in the prices of natural gas commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If a counterparty failed to perform the obligations under its contract (e.g., failed to deliver or pay for natural gas), then the Company could sustain a loss.

The Company monitors and manages the credit risk of its wholesale marketing operations through credit policies and procedures that management believes reduce overall credit risk. These policies include a review and evaluation of current and prospective counterparties' financial statements and/or credit ratings, daily monitoring of counterparties' credit limits and exposure, daily communication with traders regarding credit status and the use of credit mitigation measures, such as collateral requirements and netting agreements. Examples of collateral include letters of credit and cash received for either prepayment or margin deposit. Collateral may be requested due to the Company's election not to extend credit or because exposure exceeds defined thresholds. Most of the Company's wholesale marketing contracts contain standard netting provisions. These contracts include those governed by the International Swaps and Derivatives Association (ISDA) and the North American Energy Standards Board (NAESB). The netting provisions refer to payment netting, whereby receivables and payables with the same counterparty are offset and the resulting net amount is paid to the party to which it is due.

Internally-rated exposure applies to counterparties that are not rated by Standard & Poor's (S&P) or Moody's Investors Service, Inc. (Moody's). In these cases, the company's or guarantor's financial statements are reviewed, and similar methodologies and ratios used by S&P and/or Moody's are applied to arrive at a substitute rating. Gross credit exposure is defined as the unrealized fair value of physical and financial derivative commodity contracts plus any outstanding wholesale receivable for the value of natural gas delivered and/or financial derivative commodity contract that has settled for which payment has not yet been received. The amounts presented below have not been reduced by any collateral received or netting and exclude accounts receivable for retail natural gas sales and services.

The following is a summary of gross credit exposures grouped by investment and noninvestment grade counterparties, as of September 30, 2012.

(Thousands)	**Gross Credit Exposure**
Investment grade	**$ 11,817**
Noninvestment grade	**62**
Internally rated investment grade	**461**
Internally rated noninvestment grade	**245**
Total	**$ 12,585**

Conversely, certain of the Company's derivative instruments are linked to agreements containing provisions that would require cash collateral payments from the Company if certain events occur. These provisions vary based upon the terms in individual counterparty agreements and can result in cash payments if the Company's credit rating were to fall below its current level. The Company's credit rating, with respect to S&P, reflects the overall corporate credit profile. Specifically, most, but not all, of these additional payments will be triggered if the Company's debt is downgraded by the major credit agencies, regardless of investment grade status. As well, some of these agreements include threshold amounts that would result in additional collateral payments if the values of derivative liabilities were to exceed the maximum values provided for in relevant counterparty agreements. Other provisions include payment features that are not specifically linked to ratings, but are based on certain financial metrics.

Collateral amounts associated with any of these conditions, are determined based on a sliding scale and are contingent upon the degree to which the Company's credit rating and/or financial metrics deteriorate, and the extent to which liability amounts exceed applicable threshold limits. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position on September 30, 2011, was $1.4 million, for which the Company had not posted any collateral. There was no aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position on September 30, 2012. If all the thresholds related to the credit-risk-related contingent features underlying these agreements had been invoked on September 30, 2012 and 2011, the Company would not have been required to post any additional collateral to its counterparties. These amounts differ from the respective net derivative liabilities reflected in the Balance Sheets because the agreements also include clauses, commonly known as “Rights of Offset,” that would permit the Company to offset its derivative assets against its derivative liabilities for determining additional collateral to be posted.

5. FAIR VALUE

Fair Value of Assets and Liabilities

The fair value of cash and cash equivalents, commercial paper and borrowings under revolving credit facilities are estimated to equal their carrying amounts due to the short maturity of those instruments. The estimated fair value of long-term debt, including current maturities and excluding capital leases, as applicable is as follows:

	September 30,	
(Thousands)	**2012**	2011
Carrying value	**$ 329,845**	$ 329,845
Fair market value	**$ 364,394**	$ 357,930

Effective January 1, 2012, the Company changed its valuation technique from a market approach to an income approach. The Company considers the discounted cash flow method to provide a more consistently reliable fair value. Inputs include observable municipal and corporate yields, as appropriate for NJR's credit rating. As of September 30, 2012 and 2011, the Company discloses its debt within Level 2 of the fair value hierarchy.

Fair Value Hierarchy

The Company applies fair value measurement guidance to its financial assets and liabilities, as appropriate, which include financial derivatives. In addition, authoritative accounting literature prescribes the use of a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value based on the source of the data used to develop the price inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to inputs that are based on unobservable market data and include the following:

Level 1 Unadjusted quoted prices for identical assets or liabilities in active markets; the Company's Level 1 assets and liabilities include exchange traded futures contracts, listed equities, and money market funds.

Level 2 Price data, which includes both commodity and basis price data other than Level 1 quotes, that is observed either directly or indirectly from publications or pricing services; the Company's Level 2 assets and liabilities include over-the-counter physical forward commodity contracts and swap contracts or derivatives that are initially valued using observable quotes and are subsequently adjusted to include time value, credit risk or estimated transport pricing components for which no basis price is available. These additional adjustments are not considered significant to the ultimate recognized values.

Level 3 Inputs derived from a significant amount of unobservable market data; these include the Company's best estimate of fair value and are derived primarily through the use of internal valuation methodologies.

The Company's financial derivatives portfolios consist mainly of futures, options and swaps. The Company primarily uses the market approach and its policy is to use actively quoted market prices when available. The principal market for its derivative transactions is the natural gas wholesale market, therefore, the primary source for its price inputs is the New York Mercantile (NYMEX) exchange.

When the Company determines fair values, measurements are adjusted, as needed, for credit risk associated with its counterparties, as well as its own credit risk. The Company determines these adjustments by using historical default probabilities that correspond to the applicable Standard and Poor's issuer ratings, while also taking into consideration collateral and netting arrangements that serve to mitigate risk.

Assets and liabilities measured at fair value on a recurring basis are summarized as follows:

(Thousands)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
As of September 30, 2012:				
Assets:				
Financial derivative contracts - natural gas	$ 7,201	$ 2	$ —	$ 7,203
Total assets at fair value	**$ 7,201**	**$ 2**	$ —	**$ 7,203**
Liabilities:				
Financial derivative contracts - natural gas	$ 5,031	$ 3	$ —	$ 5,034
Total liabilities at fair value	**$ 5,031**	**$ 3**	**$ —**	**$ 5,034**
As of September 30, 2011:				
Assets:				
Financial derivative contracts - natural gas	$ 2,869	$ 2,557	$ —	$ 5,426
Total assets at fair value	$ 2,869	$ 2,557	$ —	$ 5,426
Liabilities:				
Financial derivative contracts - natural gas	$ 9,184	$ 4,694	$ —	$ 13,878
Total liabilities at fair value	$ 9,184	$ 4,694	$ —	$ 13,878

6. DEBT

The following table presents the long-term debt of the Company as of September 30:

(Thousands)			**2012**	2011
Long-Term Debt				
First mortgage bonds:		Maturity date:		
5.00%	Series HH	December 1, 2038	**12,000**	12,000
4.50%	Series II	August 1, 2023	**10,300**	10,300
4.60%	Series JJ	August 1, 2024	**10,500**	10,500
4.90%	Series KK	October 1, 2040	**15,000**	15,000
5.60%	Series LL	May 15, 2018	**125,000**	125,000
Variable	Series MM	September 1, 2027	**9,545**	9,545
Variable	Series NN	August 1, 2035	**41,000**	41,000
Variable	Series OO	August 1, 2041	**46,500**	46,500
4.77% Unsecured senior notes		March 15, 2014	**60,000**	60,000
Capital lease obligation-Buildings		June 1, 2021	**21,907**	23,314
Capital lease obligation-Meters		Various dates	**30,887**	30,683
Capital lease obligation-Equipment		December 1, 2013	**290**	530
Less: Current maturities of long-term debt			**(7,760)**	(7,575)
Total long-term debt			**$ 375,169**	$ 376,797

Annual long-term debt redemption requirements, excluding capital leases, are as follows (in millions):

September 30,	Redemption
2013	$ —
2014	$ 60.0
2015	$ —
2016	$ —
2017	$ —
Thereafter	$ 269.8

First Mortgage Bonds

The Company's mortgage secures its First Mortgage Bonds and represents a lien on substantially all of its property, including natural gas supply contracts. Certain indentures supplemental to the mortgage include restrictions as to cash dividends and other distributions on the Company's common stock that apply as long as certain series of First Mortgage Bonds are outstanding. As of September 30, 2012, under the most restrictive provision, $314 million of the Company's retained earnings was available for dividends.

Through September 7, 2011, the Company was obligated with respect to several loan agreements securing six series of variable rate bonds issued by the New Jersey Economic Development Authority (NJEDA) totaling $97 million. These bonds were commonly referred to as auction-rate securities (ARS) and had an interest rate reset every seven or thirty-five days, depending upon the applicable series. On those dates, an auction was held for the purposes of determining the interest rate of the securities. The interest rates associated with the Company's variable-rate debt were based on the rates of the related ARS. Through their subsequent redemption, all of the auctions surrounding the ARS had failed, resulting in those bonds bearing interest at their maximum rates, as defined as the lesser of (i) 175 percent of thirty-day London inter-bank offered rate (LIBOR) or (ii) 10 to 12 percent per annum, as applicable to such series of ARS. While the failure of the ARS auctions did not signify or constitute a default on the Company, the ARS did impact the Company's borrowing costs of the variable-rate debt. On August 29, 2011, due to the lack of liquidity in the market for ARS, and the resulting exposure of the Company to the LIBOR-based maximum rate, the Company completed a refunding of the ARS, whereby the NJEDA issued three series of Variable Rate Demand Notes (VDRN) with a total principal amount of $97 million and maturity dates ranging from September 2027 to August 2041. The proceeds from the issuance of the VRDN were used to refund the entire $97 million principal amount of ARS, which were retired upon redemption. The First Mortgage Bonds were canceled upon the redemption of the EDA ARS and the corresponding loan agreements were terminated and replaced with a new loan agreement securing the payment of principal and interest on the VRDNs by the Company. Costs associated with the issuance of the VRDNs, as well as remaining unamortized debt costs associated with the ARS, will be amortized over the life of the VRDNs in accordance with ASC 980, *Regulated Operations,* therefore, there was no impact to income upon extinguishment of the ARS.

The rates on these types of investments are generally correlated with the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap Index and will initially accrue interest at a daily rate, with a maximum rate of 12 percent per annum. As of September 30, 2012, the interest rate on these securities was .22 percent.

VRDNs are sold to investors on a daily basis with the interest rate set by the remarketing agent. In the case where the remarketing agent is unable to sell the VRDNs to an investor on a given day, the Company would be required to repurchase the EDA Bonds. Therefore, in conjunction with the issuance of the EDA

Bonds, the Company entered into a $100 million four-year credit facility, which expires on August 31, 2015, to provide liquidity support in the event of a failed remarketing of the EDA Bonds and to ensure payment of principal and interest. There would be no increase in debt if this were to occur.

On October 1, 2010, upon maturity, the Company redeemed its $20 million, 6.88 percent Series CC First Mortgage bonds.

On October 4, 2012, the BPU approved a petition filed by the Company requesting authorization over a three-year period to issue debt, renew its revolving credit facility expiring August 2014, renew its credit facility supporting the Company's obligations with respect to bonds issued by the New Jersey Economic Development Authority, enter into interest rate risk management transactions and increase the size of its meter leasing program on a permanent basis.

Sale-Leasebacks

The Company's master lease agreement for its headquarters building has a twenty-five and a half-year term that expires in June 2021, with two five-year renewal options. The present value of the agreement's minimum lease payments is reflected as both a capital lease asset and a capital lease obligation, which are included in utility plant and long-term debt, respectively, on the Balance Sheets.

The Company received $6.5 million and $5.9 million for fiscal 2012 and 2011, respectively, in connection with the sale-leaseback of its natural gas meters. During fiscal 2012 and 2011, the Company exercised early purchase options with respect to meter leases by making final principal payments of $1 million and 3.9 million, respectively. This sale-leaseback program is expected to continue on an annual basis.

Contractual commitments for capital lease payments, as of the fiscal years ended September 30, are as follows (in millions):

(Millions)	Lease Payment
2013	$10.7
2014	10.2
2015	9.6
2016	9.9
2017	8.7
Thereafter	16.7
Subtotal	65.8
Less: interest component	(12.7)
Total	**$53.1**

Short-term Debt

A summary of the Company's credit facilities, which require commitment fees on the unused amounts, as of September 30, are as follows:

(Thousands)	**2012**	2011
Bank credit facility dedicated to EDA Bonds	**$ 100,000**	$ 100,000
Bank credit facilities	**$ 200,000**	$ 200,000
Amount outstanding at end of period	**$ 135,000**	$ 26,500
Weighted average interest rate at end of period	**0.18%**	0.24%
Amount available at end of period	**$ 65,000**	$ 173,500

The Company had a $200 million revolving unsecured committed credit facility, which was due to expire in December 2012. On August 24, 2011, the Company replaced the facility with a new $200 million unsecured committed credit facility expiring August 2014. The credit facility is used to support the Company's commercial paper program and provides for the issuance of letters of credit. It also permits an increase to the facility, from time to time, with the existing or new lenders, in a minimum of $15 million increments up to a maximum of $50 million at the lending banks' discretion.

7. EMPLOYEE BENEFIT PLANS

Pension and Other Postemployment Benefit Plans (OPEB)

The Company has two trusteed, noncontributory defined benefit retirement plans covering regular represented and nonrepresented employees with more than one year of service. All non-represented employees hired on or after October 1, 2009, and represented employees hired on or after January 1, 2012, are covered by an enhanced defined contribution plan instead of the defined benefit plan.

Defined benefit plan benefits are based on years of service and average compensation during the highest sixty consecutive months of employment.

The Company also maintains an unfunded nonqualified pension equalization plan (PEP) that was established to provide employees with the full level of benefits as stated in the qualified plan without reductions due to various limitations imposed by the provisions of federal income tax laws and regulations. There were no plan assets in the nonqualified plan due to the nature of the plan.

The Company provides postemployment medical and life insurance benefits to employees who meet certain eligibility requirements.

The Company's funding policy for its pension plans is to contribute at least the minimum amount required by the ERISA, as amended. In fiscal 2012 and 2011, the Company had no minimum funding requirements. The Company does not expect to be required to make additional contributions to fund the pension plans over the next three fiscal years based on current actuarial assumptions; however, funding requirements are uncertain and can depend significantly on changes in actuarial assumptions, returns on plan assets and changes in the demographics of eligible employees and covered dependents. In addition, as in the past, the Company may elect to make contributions in excess of the minimum required amount to the plans. The Company made discretionary contributions to the pension plans of $20 million in both December 2012 and 2011. The Company elected to make these discretionary tax-deductible contributions to improve the funded status of the pension plans.

There are no Federal requirements to pre-fund OPEB benefits. However, the Company is required to fund certain amounts due to regulatory agreements with the BPU. The Company contributed $5.8 million and $6.5 million, respectively, in fiscal 2012 and 2011 and estimates that it will contribute between $4 million to $6 million over the next five years. Additional contributions may be required based on market conditions and changes to assumptions.

The Company's OPEB plans provide prescription drug benefits that are actuarially equivalent to those provided by Medicare Part D, for which the Company qualifies for federal subsidies. As a result of the Patient Protection and Affordable Care Act, which was enacted in March 2010, beginning in fiscal 2014 the tax deduction available to the Company will be reduced to the extent its drug expenses are reimbursed under the Medicare Part D retiree drug subsidy program. Accordingly, the Company recorded a non-cash, after-tax adjustment of approximately $2.4 million. Since the Company believes the amount is recoverable through the regulatory process, it has recognized a regulatory asset of $2.4 million. In addition, the regulatory asset was grossed up by $1.6 million associated with the recovery of income taxes.

The following summarizes the changes in the funded status of the plans and the related liabilities recognized in the Balance Sheets:

	Pension [(1)]		**OPEB**	
(Thousands)	**2012**	2011	**2012**	2011
Change in Benefit Obligation				
Benefit obligation at beginning of year	**$ 125,636**	$ 114,792	**$ 80,030**	$ 67,426
Service cost	**3,559**	3,120	**2,483**	2,362
Interest cost	**6,465**	6,184	**4,137**	3,656
Plan participants' contributions	**39**	39	**29**	16
Amendments	**1,083**	—	**(2,922)**	—
Actuarial loss	**22,233**	6,083	**20,206**	8,626
Benefits paid, net of retiree subsidies received	**(4,750)**	(4,582)	**(2,169)**	(2,056)
Benefit obligation at end of year	**$ 154,265**	$ 125,636	**$ 101,794**	$ 80,030
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 87,836**	$ 90,957	**$ 30,916**	$ 27,127
Actual return on plan assets	**20,705**	1,374	**6,128**	(551)
Employer contributions	**20,045**	48	**5,775**	6,497
Benefits paid, net of plan participants' contributions	**(4,711)**	(4,543)	**(2,334)**	(2,157)
Fair value of plan assets at end of year	**$ 123,875**	$ 87,836	**$ 40,485**	$ 30,916
Funded status	**$ (30,390)**	$ (37,800)	**$ (61,309)**	$ (49,114)
Amounts recognized on the Balance Sheets				
Postemployment employee benefit liability				
Current	**$ (48)**	$ (47)	**$ (121)**	$ (117)
Non-current	**(30,342)**	(37,753)	**(61,188)**	(48,997)
Total	**$ (30,390)**	$ (37,800)	**$ (61,309)**	$ (49,114)

(1) Includes the Company's Pension Equalization Plan.

The Company recognizes a liability for its underfunded benefit plans as required by the *Compensation - Retirement Benefits* Topic of the ASC and records the offset to regulatory assets.

The following table summarizes the amounts recognized in regulatory assets as of September 30:

	Pension	OPEB
Balance at September 30, 2010	$ 62,565	$ 38,750
Amounts arising during the period:		
Net actuarial loss (gain)	12,912	11,592
Amounts amortized to net periodic costs:		
Net actuarial (loss)	(3,087)	(2,063)
Prior service cost	(35)	(68)
Net transition obligation	—	(286)
Balance at September 30, 2011 [(1)]	$ 72,355	$ 47,925
Amounts arising during the period:		
Net actuarial loss (gain)	**10,896**	**16,773**
Amounts amortized to net periodic costs:		
Net actuarial (loss)	**(3,848)**	**(2,671)**
Prior service cost	**1,046**	**(2,677)**
Net transition obligation	**—**	**(551)**
Balance at September 30, 2012 [(1)]	**$ 80,449**	**$ 58,799**

(1) Balance represents amounts recognized in accordance with ASC 715 and excludes $308,000 and $609,000 associated with a regulatory asset approved by the BPU for both fiscal 2012 and 2011, respectively.

Amounts included in regulatory assets expected to be recognized as components of net periodic benefit cost in fiscal 2013 are as follows:

(Thousands)	Pension	OPEB
Net actuarial gain	**$ 5,719**	**$ 3,743**
Prior service credit	**105**	**(301)**
Net transition obligation	**—**	**22**
Total	**$ 5,824**	**$ 3,464**

The accumulated benefit obligation (ABO) for the pension plans, including the Pension Equalization Plan exceeded the fair value of plan assets. The projected benefit and accumulated benefit obligations and the fair value of plan assets are as follows:

	Pension	
(Thousands)	**2012**	2011
Projected benefit obligation	**$ 154,265**	$ 125,636
Accumulated benefit obligation	**$ 137,613**	$ 112,312
Fair value of plan assets	**$ 123,875**	$ 87,836

The components of the net periodic cost for pension benefits, including the Company's Pension Equalization Plan, and OPEB costs (principally health care and life insurance) for employees and covered dependents were as follows:

	Pension		OPEB	
(Thousands)	**2012**	2011	**2012**	2011
Service cost	**$ 3,559**	$ 3,120	**$ 2,483**	$ 2,362
Interest cost	**6,465**	6,184	**4,137**	3,656
Expected return on plan assets	**(9,368)**	(8,203)	**(2,695)**	(2,415)
Recognized actuarial loss	**3,848**	3,087	**2,671**	2,063
Prior service cost amortization	**36**	35	**19**	68
Recognized net initial obligation	**—**	—	**286**	286
Net periodic benefit cost	**$ 4,540**	$ 4,223	**$ 6,901**	$ 6,020

The weighted average assumptions used to determine benefit costs during the fiscal year and obligations as of September 30, are as follows:

	Pension		OPEB	
	2012	2011	**2012**	2011
Benefit costs:				
Discount rate	**5.25%**	5.5%	**5.25%**	5.5%
Expected asset return	**8.25%**	8.25%	**8.25%**	8.25%
Compensation increase	**3.25%**	2.50/3.25%	**3.25%**	3.25%
Obligations:				
Discount rate	**4.3%**	5.25%	**4.3%**	5.25%
Compensation increase	**3.25%**	3.25%	**3.25%**	3.25%

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

Information relating to the assumed health care cost trend rate (HCCTR) used to determine expected OPEB benefits as of September 30, and the effect of a one percent change in the rate, are as follows:

($ in thousands)	**2012**	2011
HCCTR	**7.5%**	8.2%
Ultimate HCCTR	**4.8%**	4.8%
Year ultimate HCCTR reached	**2022**	2019
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	**$ 17,931**	$ 13,932
Total service and interest cost	**$ 1,409**	$ 1,290
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	**$ (14,348)**	$ (11,169)
Total service and interest costs	**$ (1,099)**	$ (1,006)

The Company's investment objective is a long-term real rate of return on assets before permissible expenses that is approximately 8 percent greater than the assumed rate of inflation as measured by the consumer price index. The expected long-term rate of return is based on the asset categories in which the Company invests and the current expectations and historical performance for these categories.

The mix and targeted allocation of the pension and OPEB plans' assets are as follows:

Asset Allocation	2013 Target Allocation	Assets at September 30, 2012	2011
U.S. equity securities	39%	**39%**	35%
International equity securities	20	**21**	18
Fixed income	41	**40**	47
Total	100%	**100%**	100%

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid during the following years:

(Thousands)	Pension	OPEB
2013	$ 5,278	$ 2,804
2014	$ 5,562	$ 3,187
2015	$ 5,886	$ 3,583
2016	$ 6,222	$ 3,997
2017	$ 6,522	$ 4,443
2018 - 2022	$ 39,604	$ 28,890

The Company 's OPEB plans provide prescription drug benefits that are actuarially equivalent to those provided by Medicare Part D. Therefore, under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 the Company qualifies for federal subsidies.

The estimated subsidy payments are:

Fiscal Year	Estimated Subsidy Payment *(Thousands)*
2013	$ 218
2014	$ 233
2015	$ 251
2016	$ 272
2017	$ 293
2018 - 2022	$ 1,873

Pension assets held in the master trust, measured at fair value are summarized as follows:

(Thousands)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
As of September 30, 2012:				
Assets:				
Money market funds	**$ —**	**$ —**	**$ —**	**$ —**
Registered Investment Companies-				
Equity Funds:				
Large Cap Fund	**—**	**—**	**—**	**—**
Large Cap Index Fund	**40,884**	**—**	**—**	**40,884**
Small Cap Fund	**7,424**	**—**	**—**	**7,424**
World Equity Ex-US Fund	**25,469**	**—**	**—**	**25,469**
Fixed Income Funds:				
Emerging Markets Debt Fund	**6,229**	**—**	**—**	**6,229**
High Yield Bond Fund	**12,364**	**—**	**—**	**12,364**
Long Duration Fund	**31,505**	**—**	**—**	**31,505**
Total assets at fair value	**$ 123,875**	**$ —**	**$ —**	**$ 123,875**
As of September 30, 2011:				
Assets:				
Money market funds	$ —	$ —	$ —	$ —
Registered Investment Companies-				
Equity Funds:				
Large Cap Fund	13,253	—	—	13,253
Large Cap Index Fund	13,372	—	—	13,372
Small Cap Fund	4,597	—	—	4,597
World Equity Ex-US Fund	14,836	—	—	14,836
Fixed Income Funds:				
Emerging Markets Debt Fund	4,343	—	—	4,343
High Yield Bond Fund	8,860	—	—	8,860
Long Duration Fund	28,575	—	—	28,575
Total assets at fair value	$ 87,836	**$ —**	**$ —**	$ 87,836

OPEB assets held in the Master Trust, measured at fair value are summarized as follows:

(Thousands)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
As of September 30, 2012:				
Assets:				
Money market funds	**$ 1,142**	**$ —**	**$ —**	**$ 1,142**
Registered Investment Companies-				
Equity Funds:				
Large Cap Fund	**—**	**—**	**—**	**—**
Large Cap Index Fund	**13,022**	**—**	**—**	**13,022**
Small Cap Fund	**2,345**	**—**	**—**	**2,345**
World Equity Ex-US Fund	**8,046**	**—**	**—**	**8,046**
Fixed Income Funds:				
Core Fixed Income Fund	**10,057**	**—**	**—**	**10,057**
Emerging Markets Debt Fund	**1,968**	**—**	**—**	**1,968**
High Yield Bond Fund	**3,905**	**—**	**—**	**3,905**
Total assets at fair value	**$ 40,485**	**$ —**	**$ —**	**$ 40,485**
As of September 30, 2011:				
Assets:				
Money market funds	$ 1,567	$ —	$ —	$ 1,567
Registered Investment Companies-				
Equity Funds:				
Large Cap Fund	4,687	—	—	4,687
Large Cap Index Fund	4,746	—	—	4,746
Small Cap Fund	1,565	—	—	1,565
World Equity Ex-US Fund	5,460	—	—	5,460
Fixed Income Funds:				
Core Fixed Income Fund	8,230	—	—	8,230
Emerging Markets Debt Fund	1,563	—	—	1,563
High Yield Bond Fund	3,098	—	—	3,098
Total assets at fair value	$ 30,916	$ —	$ —	$ 30,916

The plan had no Level 2 or Level 3 fair value measurements during the two fiscal years and there have been no changes in valuation methodologies as of September 30, 2012. The following is a description of the valuation methodologies used for assets measured at fair value:

Money Market funds: Represents bank balances and money market funds which are valued based on the net asset value of shares held at year end.

Registered Investment Companies: Equity and fixed income funds valued at the net asset value (NAV) of shares held by the plan at year end as reported on the active market on which the individual securities are traded.

The methods previously described may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Defined Contribution Plan

The Company offers an Employees' Retirement Savings Plan (Savings Plan) to eligible employees. The Company matches 50 percent of participants' contributions up to 6 percent of base compensation. The Company's non-represented employees hired on or after October 1, 2009, and represented employees hired on or after January 1, 2012, are eligible for an employer special contribution of between 2 percent and 3 percent of base compensation, depending on years of service, into the Savings Plan on their behalf. The amount expensed and contributed for the matching provision of the Savings Plan was $1 million in fiscal 2012 and $921,000 in fiscal 2011. The amount contributed for the employer special contribution of the Savings Plan was $8,000 and $1,500 in fiscal 2012, and fiscal 2011, respectively.

8. ASSET RETIREMENT OBLIGATIONS (ARO)

The Company recognizes AROs related to the costs associated with cutting and capping its main and service gas distribution pipelines, which are required by New Jersey law when taking such gas distribution pipeline out of service.

The following is an analysis of the change in the ARO liability for the fiscal year ended September 30:

(Thousands)	**2012**	2011
Balance at October 1	**$ 27,026**	$ 26,009
Accretion	**1,774**	1,663
Additions	**380**	180
Retirements	**(1,197)**	(826)
Balance at period end	**$ 27,983**	$ 27,026

Accretion amounts are deferred as a regulatory asset and netted against regulatory liabilities, for presentation purposes, on the Balance Sheets.

Accretion for the next five years is estimated to be as follows:

(Thousands)

Fiscal Year Ended September 30,	**Estimated Accretion**
2013	$ 1,866
2014	1,948
2015	2,009
2016	2,069
2017	2,121
Total	$ 10,013

9. INCOME TAXES

A reconciliation of the United States federal statutory rate of 35 percent to the effective rate from operations for the fiscal years ended September 30, 2012 and 2011 are as follows:

(Thousands)	**2012**	2011
Statutory income tax expense	**$ 38,980**	$ 39,075
Change resulting from:		
State income taxes	**4,107**	5,054
Depreciation and cost of removal	**(3,999)**	(2,558)
Investment tax credits (ITC)	**(322)**	(322)
Other	**(631)**	(927)
Income tax provision	**$ 38,135**	$ 40,322
Effective income tax rate	**34.2%**	36.1%

The income tax provision (benefit) from operations consists of the following:

(Thousands)	**2012**	2011
Current		
Federal	**$ 13,186**	$ 19,649
State	**2,268**	8,967
Deferred		
Federal	**18,936**	13,219
State	**4,067**	(1,191)
Investment tax credits	**(322)**	(322)
Income tax provision	**$ 38,135**	$ 40,322

The temporary differences, which give rise to deferred tax assets and (liabilities), consist of the following:

(Thousands)	**2012**	2011
Deferred tax assets		
Investment tax credits	**$ 3,182**	$ 3,353
Incentive compensation	**1,898**	—
Over-recovered gas costs	**—**	1,866
Other	**5,802**	5,358
Total deferred tax assets	**$ 10,882**	$ 10,577
Deferred tax liabilities		
Property related items	**$ (259,587)**	$ (244,333)
Remediation costs	**(24,018)**	(30,459)
Post employment benefits	**(21,298)**	(15,093)
Conservation incentive plan	**(11,200)**	(3,697)
Under-recovered gas costs	**(2,835)**	—
Other	**(3,428)**	(4,881)
Total deferred tax liabilities	**$ (322,366)**	$ (298,463)
Total net deferred tax liabilities	**$ (311,484)**	$ (287,886)

The Company's federal income tax returns through fiscal 2009 have either been reviewed by the IRS, or the related statute of limitations has expired and all matters have been settled. The IRS is currently examining fiscal 2010 tax return.

The State of New Jersey has completed its sales and use tax examinations through March 31, 2010, and its corporate business tax examinations through September 30, 2008. All periods subsequent to those ended September 30, 2008, are statutorily open to examination.

The Company evaluates its tax positions to determine the appropriate accounting and recognition of potential future obligations associated with unrecognized tax benefits. As of September 30, 2012 and 2011, based on its analysis, the Company determined that there was no need to recognize any liabilities associated with uncertain tax positions.

10. COMMITMENTS AND CONTINGENT LIABILITIES

Cash Commitments

The Company has entered into long-term contracts, expiring at various dates through August 2030, for the supply, storage and delivery of natural gas. These contracts include current annual fixed charges of approximately $91 million at current contract rates and volumes, which are recoverable through BGSS.

Commitments as of September 30, 2012, for natural gas purchases and future demand fees for the next five fiscal year periods are as follows:

(Thousands)	2013	2014	2015	2016	2017	Thereafter
Natural gas purchases	$ 104,827	$ 104,262	$ 113,055	$ 9,442	$ 131	$ —
Storage demand fees	29,721	24,913	15,854	11,069	9,990	23,247
Pipeline demand fees	61,278	67,804	35,137	34,558	32,753	221,838
Total (1)	**$ 195,826**	**$ 196,979**	**$ 164,046**	**$ 55,069**	**$ 42,874**	**$ 245,085**

(1) Does not include amounts related to intercompany asset management agreements with NJRES.

The Company's capital expenditures are estimated at $119.3 million and $119.9 million for fiscal 2013 and 2014, respectively, and consist primarily of its construction program to support customer growth, maintenance of its distribution system and replacements needed under pipeline safety regulations. Estimated capital expenditures include SAFE construction costs of $34.6 million and $43.4 million for fiscal 2013 and 2014, respectively.

Expenditure estimates are subject to change and do not include costs associated with the restoration of damages to the Company's infrastructure that occurred subsequent to the 2012 fiscal year end as a result of Superstorm Sandy. See *Note 2. Summary of Significant Accounting Policies, Subsequent Events* for more information on the impacts of Superstorm Sandy. Furthermore, estimated expenditures are reviewed on a regular basis and may vary based on the ongoing effects of regulatory constraints, environmental regulations, unforeseen events, and the ability to access capital.

As of September 30, 2012, the Company's future minimum lease payments under various operating leases will not be more than $1.7 million annually for the next five years and $267,000 in the aggregate for all years thereafter.

Guarantees

The Company enters into agreements to lease vehicles, generally over a five-year term, that qualify as operating leases. These agreements contain provisions that could require the Company to make additional cash payments at the end of the term for a portion of the residual value of the vehicles. As of September 30, 2012, the present value of the liability recognized on the Balance Sheets is $650,000. In the event performance under the guarantee is required, the Company's maximum future payment would be $922,000.

Legal Proceedings

Manufactured Gas Plant Remediation

The Company is responsible for the remedial cleanup of five MGP sites, dating back to gas operations in the late 1800s and early 1900s that contain contaminated residues from former gas manufacturing operations. The Company is currently involved in administrative proceedings with the New Jersey Department of Environmental Protection (NJDEP), as well as participating in various studies and investigations by outside consultants to determine the nature and extent of any such contaminated residues and to develop appropriate programs of remedial action, where warranted, under Administrative Consent Orders or Memoranda of Agreement with the NJDEP.

The Company may, subject to BPU approval, recover its remediation expenditures, including carrying costs, over rolling seven-year periods pursuant to a RA approved by the BPU. In January 18, 2012, the BPU approved the recovery of the remediation expenditures incurred through June 30, 2009, which maintained the expected annual recovery at approximately $20 million. In February 2012, the Company, filed its 2011 SBC filing, requesting approval of its MGP expenditures incurred through June 30, 2011, which would continue its existing overall SBC rate and recovery. As of September 30, 2012, $59.7 million of previously incurred remediation costs, net of recoveries from customers and insurance proceeds, are included in regulatory assets on the Balance Sheets.

The Company periodically and at least annually performs updated an environmental review of the MGP sites, including a review of potential liability for investigation and remedial action. The Company estimated at the time of the review that total future expenditures to remediate and monitor the five MGP sites for which it is responsible, including potential liabilities for Natural Resource Damages that might be brought by the NJDEP for alleged injury to groundwater or other natural resources concerning these sites, will range from approximately $159.6 million to $266.4 million. The Company's estimate of these liabilities is based upon known facts, existing technology and enacted laws and regulations in place when the review was completed. Where it is probable that costs will be incurred, and the information is sufficient to establish a range of possible liability, the Company accrues the best estimated amount in the range. If no point within the range is more likely than the other, it is the Company's policy to accrue the lower end of the range. Accordingly, the Company as of September 30, 2012, has recorded an MGP remediation liability and a corresponding regulatory asset of $182 million on the Balance Sheets, based on the best estimate. The actual costs to be incurred by the Company are dependent upon several factors, including final determination of remedial action, changing technologies and governmental regulations, the ultimate ability of other responsible parties to pay and any insurance recoveries.

The Company will continue to seek recovery of MGP-related costs through the RA. If any future regulatory position indicates that the recovery of such costs is not probable, the related non-recoverable costs would be charged to income in the period of such determination. However, because recovery of such costs

is subject to BPU approval, there can be no assurance as to the ultimate recovery through the RA or the impact on the Company's results of operations, financial position or cash flows, which could be material.

General

The Company is party to various other claims, legal actions and complaints arising in the ordinary course of business. In the Company's opinion, the ultimate disposition of these matters will not have a material effect on its financial condition, results of operations or cash flows.

11. RELATED PARTY TRANSACTIONS

The Company participates in various transactions with NJR and other subsidiaries of NJR in the ordinary course of business. These transactions result in either charges or credits to operation and maintenance expense in the Statements of Operations.

The following table summarizes charges from NJR and NJR Service Corporation (NJRSC) during fiscal 2012 and 2011. Charges from NJR were for various services, including executive management and corporate governance. Charges from NJRSC were primarily related to financial and administrative, legal, human resources, corporate communications, taxation, internal audit and technology services.

(*Thousands*)	**2012**	2011
NJR	**$ 6,994**	$ 6,857
NJRSC	**20,167**	19,232
Total	**$ 27,161**	$ 26,089

The following table summarizes charges from the Company to NJR Home Services (NJRHS), NJR Energy Services (NJRES), NJR, NJR Clean Energy Ventures (NJRCEV) and Commercial Realty and Resources (CR&R) during fiscal 2012 and 2011. Charges to NJRHS were for services related to billing, customer inquiry, payment processing, vehicle fleet maintenance and operating expenses. Charges to NJRES were for administrative services and operating expenses. Charges to NJR were for operating expenses. Charges to NJRCEV were for services related to billing and payment processing and operating expenses. Charges to CR&R were for operating expenses.

(*Thousands*)	**2012**	2011
NJRHS	**$ 3,624**	$ 3,608
NJRES	**556**	373
NJR	**427**	320
NJRCEV	**467**	233
CR&R	**24**	23
Total	**$ 5,098**	$ 4,557

The following table reflects the receivable (payable) the Company had with NJR and other subsidiaries of NJR including NJR Steckman Ridge Storage Company (NJRSR) at September 30, 2012 and 2011, which are included in accounts payable and other in the Balance Sheets:

(*Thousands*)	**2012**	2011
NJR	**$ (1,218)**	$ (1,478)
NJRES	**43**	1,513
NJRHS	**(432)**	(881)
CR&R	**18**	35
NJRSC	**(1,642)**	(1,687)
NJRCEV	**71**	116
NJRSR	**—**	500
Total	**$ (3,160)**	$ (1,882)

The Company may periodically purchase natural gas from NJRES. During the fiscal years ended September 30, 2012 and 2011, the Company purchased natural gas from NJRES in the amount of $2.5 million and $55.1 million, respectively.

In December 2009, the Company entered into an asset management agreement with NJRES that began in January 2010 and ends in March 2014. Under the terms of this agreement, the Company released certain transportation and storage contracts to NJRES for the entire term of the agreement. The Company also sold approximately 1 Bcf of natural gas in storage at cost to NJRES for $8 million. In return, the Company has the option to purchase index priced gas from NJRES at the Company's citygate and other delivery locations to maintain operational reliability. In September 2010, the Company and NJRES entered into an another asset management agreement that began in September 2010 and ends October 2014, whereby the Company released additional transportation contracts to NJRES for the entire term of the agreement and has the option to purchase index priced gas from NJRES at the Company's citygate.

In January 2010, the Company entered into a ten-year agreement effective April 1, 2010, for 3 Bcf of firm storage capacity with Steckman Ridge. Under the terms of the agreement, the Company incurs demand fees, at market rates, of approximately $9.3 million annually. These fees are recoverable through the Company's BGSS mechanism and are included in regulatory assets. Additionally, the Company has transportation capacity with Iroquois Gas Transmission that expires by January 2019. Demand fees associated with both Steckman Ridge and Iroquois Gas Transmission were $9 million and $9.9 million during the fiscal year ended September 30, 2012 and 2011, respectively. As of September 30, 2012 and 2011, the Company had fees payable to Steckman Ridge and Iroquois Gas Transmission in the amount of $775,000 and $61,000, respectively, for both fiscal years.