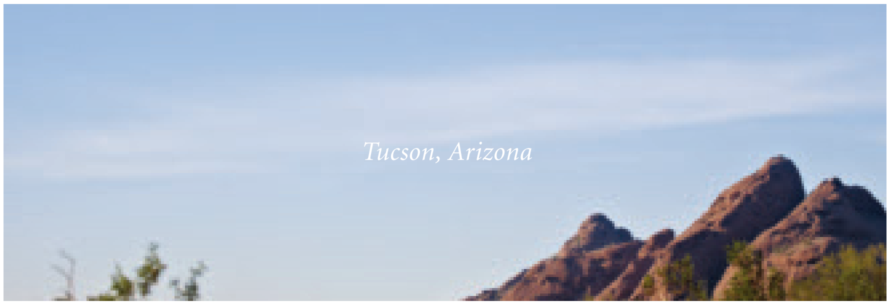
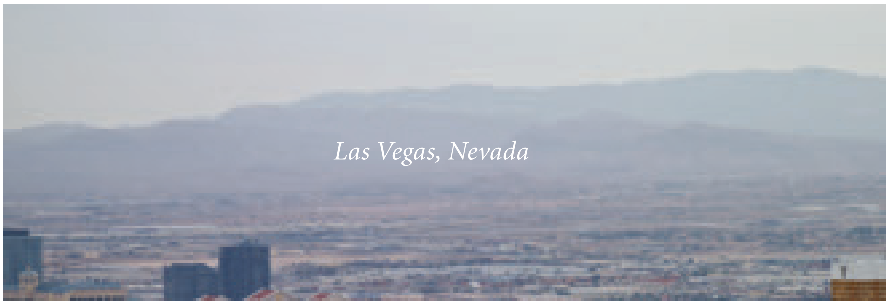
2013 Annual Report

When people work together, good ideas happen.

Southwest Gas Corporation


Tucson, Arizona


Phoenix, Arizona


Las Vegas, Nevada

And when they do, it's nice to hear about them.

The programs have been true "win-win" endeavors insofar as Southwest Gas is able to advance customer safety and reliability, while minimizing the financial impact normally associated with non-revenue producing infrastructure.

Manny Corral works to replace a COYL in southern Arizona.

While the company has historically had vigorous distribution integrity management programs in each of its operating jurisdictions, the increasing national focus on pipeline safety has presented an opportunity to further enhance these efforts by partnering with state regulatory agencies. Specifically, Southwest Gas has advocated for "infrastructure recovery mechanisms" with each of our state regulatory agencies. The mechanisms generally provide for the timely cost recovery of the company's accelerated pipe replacement efforts beyond the established levels already reflected in customer rates. Southwest Gas has received regulatory approval for a customer-owned yard line program in Arizona and several early vintage plastic pipe replacement programs in Nevada. We have also requested an annual infrastructure replacement program in California. The programs have been true "win-win" endeavors insofar as Southwest Gas is able to advance customer safety and reliability, while minimizing the financial impact normally associated with non-revenue producing infrastructure. Southwest Gas' regulators, credit rating agencies, and shareholders have been supportive of these initiatives.

Left: Manny Corral, John Hester, Karen Haller, and Clayton Saner

Safety, Service, and Reliability are at the core of what we do! Our solid pipeline safety record, impressive emergency response results and exceptional customer satisfaction ratings are just a few examples of what we have achieved together, striving for the same goal.

Daniel Spade

Safety is paramount to our company. There is nothing more important than the continued safety of our employees, customers and communities. Our field employees spend countless hours in operational and emergency response training. Additionally, all employees, regardless of their job duties, are expected to perform their work safely. Safety, Service, and Reliability are at the core of what we do! Our solid pipeline safety record, impressive emergency response results and exceptional customer satisfaction ratings are just a few examples of what we have achieved together, striving for the same goal.

To enhance field support and further coordination with other first response agencies during an incident, Southwest Gas procured eight incident command trailers. These trailers were designed by a company-wide team with broad experience in emergency response and crisis management. During large-scale incidents, a certain synergy between field personnel and crisis management staff is needed to ensure a successful conclusion. In a time of crisis, the new full-service command trailers offer amenities that meet the needs of field personnel for the duration of the incident.

Right: Photographed at our Emergency Management Response Facility in central Phoenix: Daniel Spade, Bill Moody, Anita Romero, Kale Pittman, and Eric DeBonis


CALIFORNIA
NEW MEXICO

Creating a positive and friendly workplace takes teamwork, innovation and commitment. Southwest Gas is proud to have an outstanding team with future growth prospects. We're a high-performing organization, both financially and operationally.

Elaine Babcock crosses the finish line

Southwest Gas senior officers serve on the Benefits Committee to ensure that employees continue to enjoy a positive and productive work environment. Our leaders understand the value provided to employees and their families through Southwest Gas compensation and benefits programs. The company constantly reviews health and welfare programs to ensure Southwest Gas remains competitive in the market while controlling costs. The committee constantly seeks ways to increase efficiencies by looking at health care costs, retirement programs and retention. Recently the company moved to a consumer-driven health plan and a robust wellness program. The employee wellness program has grown over the years; now employees benefit from an on-site life coach to give information, motivate, and help to better care for themselves and their families.

Creating a positive and friendly workplace takes teamwork, innovation and commitment. Southwest Gas is proud to have an outstanding team with future growth prospects. We're a high-performing organization, both financially and operationally.

Photographed: Ed Janov, Rosa Cisneros, Laura Lopez Hobbs, and Roy Centrella

Fellow shareholders,

The Board and management of Southwest Gas Corporation ("Company" or "Southwest") have long pursued a strategy that has focused on the core fundamentals of its businesses. By working collaboratively with regulatory bodies, we have received improved rate designs in all jurisdictions, resulting in more consistent revenues and cash flows, improved returns and a stronger capital structure. We have continually reviewed our operating practices to control costs and increase productivity, and pursued initiatives to invest in rate base to meet customer growth and increase the safety and reliability of our distribution system. We have also invested in the training and well-being of our valuable employees. In addition, we continue to realize solid results from our pipeline construction segment which continues to experience growth throughout the country.

We are pleased to report 2013 earnings per share of $3.14, a 9% increase over the $2.89 reported in 2012 and the highest in the Company's history. The earnings were again driven by strong performance in the natural gas segment of our business, which contributed $124.2 million in net income in 2013, compared to $116.6 million the prior year; and a 2013 net income contribution of $21.2 million from NPL Construction Co. ("NPL"), our wholly owned pipeline construction subsidiary, compared to $16.7 million in 2012. Furthermore, for the eighth straight year, the Board recently approved an increase in the annualized dividend on common stock, from $1.32 to 1.46, a 10.6% increase.

At year end 2013, Southwest had 1,904,000 customers, an increase of 28,000 for the year, and a healthy improvement over the previous year's increase of 17,000 customers. We expect a similar growth level in 2014 as the southwestern part of the country continues its slow but steady recovery from the depths of the recession.

To support customer growth and also to support our ongoing pipe replacement efforts, we invested $315 million in capital expenditures over the last 12 months. We estimate we will invest $375 million in 2014 and about $1.1 billion during the next three years. With capital expenditures being incurred at such a healthy pace, we need to access the capital markets periodically to supplement internally generated cash. In October 2013, we issued $250 million of 30 year notes at an all-in cost of just below 5%. We were quite pleased to add this low cost instrument to our debt portfolio, which will benefit our customers for decades to come.

In recognition of the continued progress we've made on the regulatory front and through improvements made to cash flows and capital structure, all three major rating agencies upgraded the Company's unsecured credit ratings. Standard and Poor's increased its rating from BBB+ to A- and Fitch raised its rating from A- to A during the first and second quarters of 2013, respectively, and Moody's increased its rating from Baa1 to A3 in January 2014. These strong investment grade credit ratings place us in a stronger position to access the capital markets even during distressed economic conditions.

The Company continues to focus on cost containment efforts. During 2013, operating costs for the gas segment of our business increased 4%. Although at first glance this appears high, there were a number of factors influencing the overall change which tell the full story. Pension costs increased $6.4 million from 2012 to 2013 and accounted for approximately 1% of the overall cost increase. In addition, amortization expense and general tax increases amounting to $8 million, for which the Company received offsetting revenue, made up another 1% of the change between periods. Net of these factors, operating costs rose by just 2% between periods. And our customer satisfaction rating for the year continued to average well over 90%, one of the best such ratings in our industry.

Going forward, the Company expects to experience operating cost increase pressures resulting from heightened pipeline safety and system reliability mandates. These are areas of emphasis in which the Company will not trade off higher risk for lower costs. We will look to mitigate these cost increases through continued focus on technological advances in areas such as billing and payment processing, call center optimization, and customer service field automation. Our goal is to keep operating costs inside the combined rate of inflation and customer growth.

We continue to make strides in working with our regulators to improve revenues and cash flows. In February of this year, Southwest received a proposed decision in the California rate case application that it submitted to the California Public Utilities Commission in December 2012. The proposed decision includes a base year margin increase of $7.5 million; a final decision is expected in the near future.

Beyond rate case filings, Southwest continues to partner with our state regulators on initiatives that serve our customers' interests, while recovering our costs of service. Last year marked the second year of decoupled rate design effectiveness across our services territories, and featured the Arizona Corporation Commission's ("ACC") first annual review of that state's decoupling mechanism; the ACC concluded that the mechanism was working as designed, to the mutual benefit of customers and the Company.

Regulators have also been very supportive of Southwest's initiatives to fund additional infrastructure investment designed to increase customer safety, service and reliability. In Nevada, Southwest received approval from the Public Utilities Commission of Nevada ("PUCN") to replace $15.6 million of early vintage plastic pipe in 2013 with a cost recovery mechanism. More broadly, the PUCN also approved a new regulation establishing a template for future accelerated pipe replacement plans that provides for surcharge cost recovery in between general rate case filings. More recently, in early 2014, the PUCN also approved an $18.9 million proposal for accelerated 2014 pipe replacement, again with a cost recovery tracker.

In Arizona, Southwest Gas requested, and was granted, permission to expand its program to replace customer-owned yard lines; the program expansion will allow for more aggressive replacement of customer-owned facilities, with annual surcharge cost recovery. It should also be noted that the previously referenced California rate case proposed decision includes approval of an infrastructure replacement mechanism. Management believes that regulators' support of infrastructure replacement trackers has been a true "win-win" for customers, regulators, and the Company, allowing significant advancement of our collective interest in maximizing public safety.

Additional customer-oriented investments have also been proposed to augment gas supply delivery. At our Paiute Pipeline subsidiary, we have proposed a new $35 million, 35-mile lateral to connect Ruby Pipeline to the economically thriving Elko, Nevada area. Separately, Southwest has proposed a $55 million liquefied natural gas storage facility to enhance deliveries to our Tucson area customers. Regulatory decisions on the Paiute lateral and the Tucson storage proposals are anticipated within the coming twelve months. Natural gas service continues to be a compelling economic energy alternative for our customers, and Southwest Gas is strategically investing in the facilities needed to serve our customers' growing demands.

As we've disclosed in past letters and annual reports, the Company holds life insurance policies on members of management and other key employees to indemnify itself against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. Company earnings are impacted by changes in the value of Company-owned life insurance ("COLI") policies. The value of this investment is influenced by the investment portfolio underlying the insurance policies, and it fluctuates consistent with movements in the broader markets. Consistent with the strong performance of the broader equity markets in 2013, the Company recognized a net increase in the cash surrender values (including net death benefits recognized) of its COLI policies of $12.4 million, or $0.27 per share, compared to an increase of $6.6 million, or $0.14 per share in 2012. For a more detailed discussion regarding COLI, we encourage you to refer to Management's Discussion and Analysis in this report.

NPL posted strong operating results in 2013 as the business continued to grow. Over the past five years, operating revenues more than doubled, from $279 million in 2009 to $650 million in 2013, as did profitability, improving from $8.1 million to $21.2 million. As a result of increased pipeline safety legislation and regulatory scrutiny, many natural gas utilities have embarked on large, multi-year infrastructure replacement projects. NPL has benefitted from this work and it currently serves customers from twenty operating offices, coast to coast. Management believes the ongoing opportunities for growth are manifold and, while the principal business focus of the corporation will remain on the natural gas distribution business, the Board and management agree NPL should continue to pursue the growth opportunities that are expected to persist in the market. The aforementioned recent rapid growth has required NPL to adjust its management structure to assure consistent processes are instituted and followed throughout its operations. To distinguish itself from competitors, NPL management is intensely focused on its service and safety and, consequently, it maintains one of the strongest safety records in its industry. As it pursues growth opportunities, management will continue to concentrate on improving operating margins, returns on invested capital and contributions to the overall earnings of the Company.

In its ongoing review of dividend policy, the Board considers the adequacy and sustainability of earnings and cash flows of the Company and its subsidiaries; the strength of the Company's capital structure; the sustainability of the dividend through varying business cycles; and whether the dividend is within a normal payout range for our industry. At its February 26, 2014 meeting, the Board acted to raise the annualized dividend on common stock from $1.32 to $1.46 per share, a 10.6% increase. This represents the eighth straight year the dividend has been increased. Going forward, the Board intends to increase the dividend over time such that the Company's payout ratio approaches our local distribution company peer group average while maintaining our strong credit ratings and our ability to effectively fund future growth in both business segments.

We are committed to meet the expectations of our shareholders, our customers and those that regulate our Company. And as you can see from this letter, our focus on the fundamentals of our businesses has produced favorable results for all of our constituents.

While our strategies remain consistent, the tactics we employ within those strategies constantly change to adapt to the current operating environment. As the theme of this annual report indicates, when people come together and contribute their best ideas and efforts to specific objectives, good things happen. We are optimistic about the future prospects for our Company. The Board and senior management are confident that the business initiatives we are focused on in both segments of our Company will bring positive results and increase the value of your investment over time in Southwest Gas Corporation.

Michael J. Melarkey
Chairman of the Board

Jeffrey W. Shaw
President and Chief Executive Officer

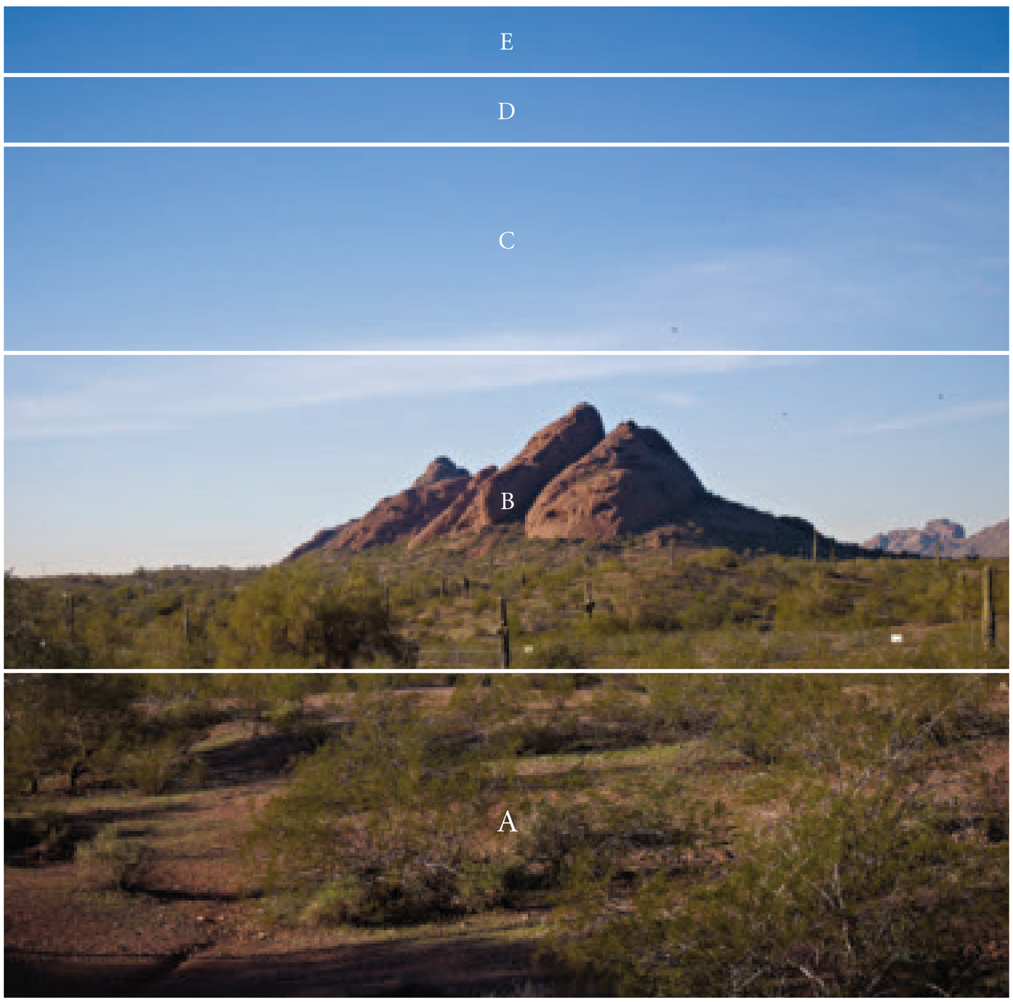
The leadership of Southwest Gas realizes that the sum of all its parts equals a whole that makes good things happen. The entire leadership team understands success takes more than one person and promotes opportunities for all employees to make a difference. New ideas and points-of-view are vital to a company's progress, and it takes a strong team to combine those fresh perspectives and implement policies that generate both a positive work environment and favorable experience for customers. We're intensely focused on delivering unparalleled value to our customers, while continuing to grow shareholder value.

Above: Standing – Anita Romero, Laura Lopez Hobbs, Karen Haller, Eric DeBonis, Roy Centrella, Edward Janov. Sitting – William Moody, Jeffrey Shaw, John Hester

Margin by Customer Class (2013)

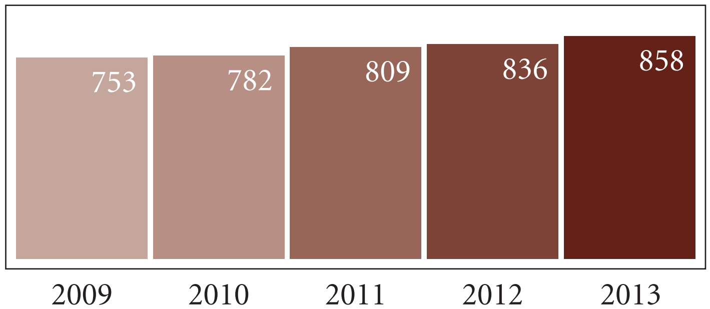
A: Residential 70% B: Small Commercial 15% C: Transportation 11%
D: Large Commercial 3% E: Industrial/Other 1%

Customers by Division (December 31, 2013)

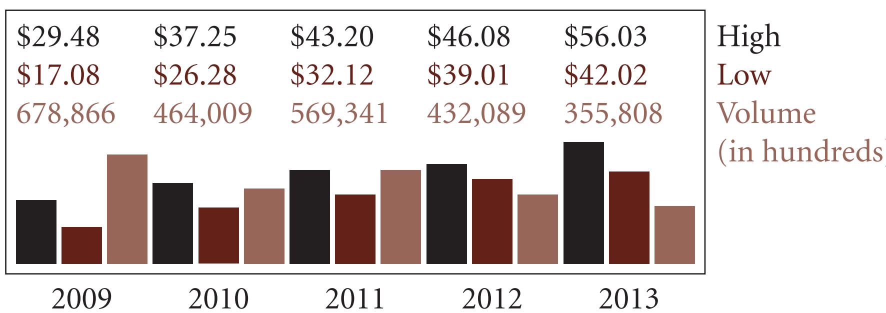


A: Southern Nevada 33% B: Central Arizona 32% C: Southern Arizona 21%
D: Southern California 7% E: Northern Nevada 7%

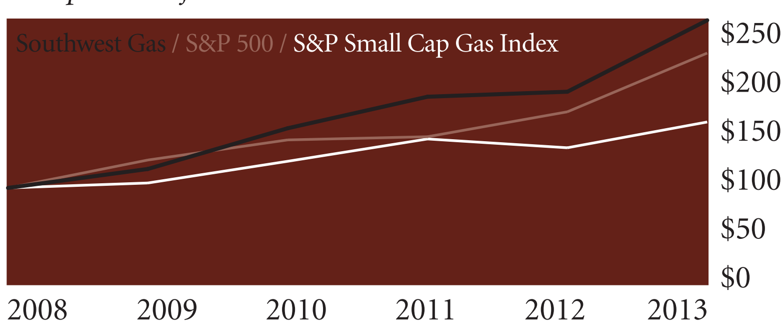
Customers Per Employee



Stock Prices and Trading Volume



Comparison of Five-Year Cumulative Total Returns



The performance graph above compares the five-year cumulative total return on Company common stock, assuming reinvestment of dividends, with the total returns on the Standard & Poor's 500 Stock Composite Index ("S&P 500") and the S&P Small Cap Gas Index, consisting of the Company and five other gas distribution companies.

The S&P Small Cap Gas Index, which is weighted by year-end market capitalization, consists of the following companies: Laclede Group Inc.; New Jersey Resources Corp.; Northwest Natural Gas Co.; Piedmont Natural Gas Company; South Jersey Industries Inc.; and the Company.

Financial Section

Consolidated Selected Financial Statistics

Year Ended December 31,	2013	2012	2011	2010	2009
(Thousands of dollars, except per share amounts)					
Operating revenues	$1,950,782	$1,927,778	$1,887,188	$1,830,371	$1,893,824
Operating expenses	1,676,567	1,656,254	1,637,108	1,598,254	1,685,433
Operating income	$ 274,215	$ 271,524	$ 250,080	$ 232,117	$ 208,391
Net income	$ 145,320	$ 133,331	$ 112,287	$ 103,877	$ 87,482
Total assets at year end	$4,565,174	$4,488,057	$4,276,007	$3,984,193	$3,906,292
Capitalization at year end					
Total equity	$1,412,395	$1,308,498	$1,225,031	$1,166,996	$1,102,086
Subordinated debentures	—	—	—	—	100,000
Long-term debt, excluding current maturities	1,381,327	1,268,373	930,858	1,124,681	1,169,357
	$2,793,722	$2,576,871	$2,155,889	$2,291,677	$2,371,443
Current maturities of long-term debt	$ 11,105	$ 50,137	$ 322,618	$ 75,080	$ 1,327
Common stock data					
Common equity percentage of capitalization	50.6%	50.8%	56.8%	50.9%	46.5%
Return on average common equity	10.6%	10.4%	9.3%	9.1%	8.1%
Basic earnings per share	$ 3.14	$ 2.89	$ 2.45	$ 2.29	$ 1.95
Diluted earnings per share	$ 3.11	$ 2.86	$ 2.43	$ 2.27	$ 1.94
Dividends declared per share	$ 1.32	$ 1.18	$ 1.06	$ 1.00	$ 0.95
Payout ratio	42%	41%	43%	44%	49%
Book value per share at year end	$ 30.51	$ 28.39	$ 26.68	$ 25.60	$ 24.44
Market value per share at year end	$ 55.91	$ 42.41	$ 42.49	$ 36.67	$ 28.53
Market value per share to book value per share	183%	149%	159%	143%	117%
Common shares outstanding at year end (000)	46,356	46,148	45,956	45,599	45,092
Number of common shareholders at year end	15,359	16,028	16,834	17,821	20,489
Ratio of earnings to fixed charges	3.90	3.61	3.21	2.87	2.46

Natural Gas Operations

Year Ended December 31,	2013	2012	2011	2010	2009
(Thousands of dollars)					
Sales	$1,212,293	$1,238,513	$1,329,512	$1,438,809	$1,547,081
Transportation	87,861	83,215	73,854	73,098	67,762
Operating revenue	1,300,154	1,321,728	1,403,366	1,511,907	1,614,843
Net cost of gas sold	436,001	479,602	613,489	736,175	866,630
Operating margin	864,153	842,126	789,877	775,732	748,213
Expenses					
Operations and maintenance	384,914	369,979	358,498	354,943	348,942
Depreciation and amortization	193,848	186,035	175,253	170,456	166,850
Taxes other than income taxes	45,551	41,728	40,949	38,869	37,318
Operating income	$ 239,840	$ 244,384	$ 215,177	$ 211,464	$ 195,103
Contribution to consolidated net income	$ 124,169	$ 116,619	$ 91,420	$ 91,382	$ 79,420
Total assets at year end	$4,272,029	$4,204,948	$4,048,613	$3,845,111	$3,782,913
Net gas plant at year end	$3,486,108	$3,343,794	$3,218,944	$3,072,436	$3,034,503
Construction expenditures and property additions	$ 314,578	$ 308,951	$ 305,542	$ 188,379	$ 212,919
Cash flow, net					
From operating activities	$ 265,290	$ 344,441	$ 216,745	$ 342,522	$ 371,416
From (used in) investing activities	(304,189)	(296,886)	(289,234)	(178,685)	(265,850)
From (used in) financing activities	44,947	(43,453)	(2,327)	(107,779)	(81,744)
Net change in cash	$ 6,048	$ 4,102	$ (74,816)	$ 56,058	$ 23,822
Total throughput (thousands of therms)					
Residential	741,327	655,046	718,765	704,693	669,736
Small commercial	298,045	270,665	303,923	300,940	294,225
Large commercial	102,761	116,582	112,256	111,833	117,241
Industrial/Other	50,210	47,830	50,208	58,922	72,623
Transportation	1,037,916	998,095	941,544	998,600	1,043,894
Total throughput	2,230,259	2,088,218	2,126,696	2,174,988	2,197,719
Weighted average cost of gas purchased ($/therm)	$ 0.42	$ 0.42	$ 0.58	$ 0.62	$ 0.71
Customers at year end	1,904,000	1,876,000	1,859,000	1,837,000	1,824,000
Employees at year end	2,220	2,245	2,298	2,349	2,423
Customer to employee ratio	858	836	809	782	753
Degree days – actual	1,918	1,740	2,002	1,998	1,824
Degree days – ten-year average	1,876	1,866	1,888	1,876	1,882

Management's Discussion and Analysis of Financial Condition and Results of Operations

About Southwest Gas Corporation

Southwest Gas Corporation and its subsidiaries (the "Company") consist of two business segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services.

Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Southwest is the largest distributor of natural gas in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. Southwest is also the largest distributor of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas for customers in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

As of December 31, 2013, Southwest had 1,904,000 residential, commercial, industrial, and other natural gas customers, of which 1,022,000 customers were located in Arizona, 695,000 in Nevada, and 187,000 in California. Residential and commercial customers represented over 99% of the total customer base. During 2013, 56% of operating margin was earned in Arizona, 34% in Nevada, and 10% in California. During this same period, Southwest earned 85% of its operating margin from residential and small commercial customers, 4% from other sales customers, and 11% from transportation customers. These general patterns are expected to remain materially consistent for the foreseeable future.

Southwest recognizes operating revenues from the distribution and transportation of natural gas (and related services) to customers. Operating margin is the measure of gas operating revenues less the net cost of gas sold. Management uses operating margin as a main benchmark in comparing operating results from period to period. The principal factors affecting changes in operating margin are general rate relief and customer growth. All of Southwest's service territories have decoupled rate structures, which are designed to eliminate the direct link between volumetric sales and revenue, thereby mitigating the impacts of weather variability and conservation on margin, allowing the Company to aggressively pursue energy efficiency initiatives.

NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that primarily provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. NPL operates in 20 major markets nationwide. Construction activity is cyclical and can be significantly impacted by changes in weather, general and local economic conditions (including the housing market), interest rates, employment levels, job growth, the equipment resale market, pipe replacement programs of utilities, and local and federal regulation (including tax rates and incentives). During the past few years, utilities have implemented or modified pipeline integrity management programs to enhance safety pursuant to federal and state mandates. These programs, coupled with bonus depreciation tax deduction incentives, have resulted in a significant increase in multi-year pipeline replacement projects throughout the country. Generally, revenues are lowest during the first quarter of the year due to less favorable winter weather conditions. Revenues typically improve as more favorable weather conditions occur during the summer and fall months. In certain circumstances, such as with large, longer duration bid contracts, or unit-price contracts with revenue caps, results may be impacted by differences between costs incurred and those anticipated when the work was originally bid.

Executive Summary

The items discussed in this Executive Summary are intended to provide an overview of the results of the Company's operations and are covered in greater detail in later sections of management's discussion and analysis. As reflected in the table below, the natural gas operations segment accounted for an average of 85% of consolidated net income over the past three years. As such, management's discussion and analysis is primarily focused on that segment.

Summary Operating Results

Year ended December 31,	2013	2012	2011
(In thousands, except per share amounts)			
Contribution to net income			
Natural gas operations	$124,169	$116,619	$ 91,420
Construction services	21,151	16,712	20,867
Consolidated	$145,320	$133,331	$112,287
Average number of common shares outstanding	46,318	46,115	45,858
Basic earnings per share			
Consolidated	$ 3.14	$ 2.89	$ 2.45
Natural Gas Operations			
Operating margin	$864,153	$842,126	$789,877

2013 Overview

Consolidated results for 2013 increased compared to 2012 due to improved results from both business segments. Basic earnings per share were $3.14 in 2013 compared to basic earnings per share of $2.89 in 2012.

Natural gas operations highlights include the following:

- Operating margin increased $22 million, or 3%, compared to the prior year
- Operating expenses increased $27 million, or 4%, between years
- Net financing costs decreased $4 million between 2013 and 2012
- Other income increased $8 million between years
- Redemption at par of $30 million of 5.45% IDRBs and $15 million of 5.80% IDRBs in March 2013 and $8.27 million of 5.55% IDRBs in September 2013 (all originally due in 2038)
- Issued $250 million of 4.875% 30-year senior notes in October 2013
- The Company's credit rating was upgraded from BBB+ to A- by Standard & Poor's, from A- to A by Fitch, and from Baa1 to A3 by Moody's Investors Service in March 2013, May 2013, and January 2014, respectively

Construction services highlights include the following:

- Revenues in 2013 increased $45 million, or 7%, compared to 2012
- Construction expenses increased $32 million or 6%, compared to 2012
- Contribution to net income increased $4 million compared to 2012

Customer Growth. Southwest completed 21,000 first-time meter sets, but realized 28,000 net new customers over the last twelve months. The incremental additions reflect a return to service of customer meters on previously vacant homes.

Southwest estimates the remaining number of excess inactive meters is approximately 26,000 at December 31, 2013 and anticipates a continued gradual return of customers associated with previously vacant homes. Southwest projects customer growth of about 1.5% for 2014.

Company-Owned Life Insurance ("COLI"). Southwest has life insurance policies on members of management and other key employees to indemnify itself against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. The COLI policies have a combined net death benefit value of approximately $238 million at December 31, 2013. The net cash surrender value of these policies (which is the cash amount that would be received if Southwest voluntarily terminated the policies) is approximately $93 million at December 31, 2013 and is included in the caption "Other property and investments" on the balance sheet. The Company currently intends to hold the COLI policies for their duration and purchase additional policies as necessary. Current tax regulations provide for tax-free treatment of life insurance (death benefit) proceeds. Therefore, the changes in the cash surrender value components of COLI policies as they progress toward the ultimate death benefits are also recorded without tax consequences. Cash surrender values are directly influenced by the investment portfolio underlying the insurance policies. This portfolio includes both equity and fixed income (mutual fund) investments. As a result, generally the cash surrender value (but not the net death benefit) moves up and down consistent with the movements in the broader stock and bond markets. The Company is considering shifting the investment mix of the underlying investment portfolio more toward fixed income to help mitigate future cash surrender value volatility in COLI policies. As indicated in Note 1 of the Notes to Consolidated Financial Statements, cash surrender values of COLI policies increased $12.4 million (including $1.4 million of incremental death benefits) in 2013 and $6.6 million in 2012. Management currently expects average returns of $3 million to $5 million annually on the COLI policies, excluding any net death benefits recognized.

Issuance and Redemption of Debt. In March 2013, the Company redeemed at par the 5.45% Series 2003C and the 5.80% Series 2003E IDRBs originally due in 2038. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. The Company facilitated these redemptions primarily from borrowings under its $300 million credit facility. In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

Liquidity. Southwest believes its liquidity position is solid. Southwest has a $300 million credit facility maturing in March 2017. The facility is provided through a consortium of eight major banking institutions. Historically, facility borrowings have been low and concentrated in the first half of the winter heating period when gas purchases require temporary financing. During 2013, credit facility usage was impacted by a $111 million reduction in deferred purchased gas cost liabilities and the extinguishment of $53 million in Clark County, Nevada IDRBs. The maximum amount outstanding on the credit facility (including a commercial paper program) during 2013 was $195 million (prior to the paydown from the senior notes). At December 31, 2013, $10 million was outstanding on the long-term portion of the credit facility (all of which was under the commercial paper program), and no borrowings were outstanding on the short-term portion of the credit facility. Southwest has no significant debt maturities prior to 2017.

Construction Services. NPL's contribution to net income for 2013 was $21.2 million, a $4.4 million increase over the results for 2012. The prior year included recognition of a $15 million pretax loss on a large fixed-price contract, partially offset by $8 million in gains on sale of equipment. The current year includes higher general and administrative expenses due to structural and transitional changes associated with NPL's increased size and business complexity and additional legal-related expenses.

Results of Natural Gas Operations

Year Ended December 31,	2013	2012	2011
(Thousands of dollars)			
Gas operating revenues	$1,300,154	$1,321,728	$1,403,366
Net cost of gas sold	436,001	479,602	613,489
Operating margin	864,153	842,126	789,877
Operations and maintenance expense	384,914	369,979	358,498
Depreciation and amortization	193,848	186,035	175,253
Taxes other than income taxes	45,551	41,728	40,949
Operating income	239,840	244,384	215,177
Other income (deductions)	12,261	4,165	(5,404)
Net interest deductions	62,555	66,957	68,777
Income before income taxes	189,546	181,592	140,996
Income tax expense	65,377	64,973	49,576
Contribution to consolidated net income	$ 124,169	$ 116,619	$ 91,420

2013 vs. 2012

Contribution to consolidated net income from natural gas operations increased by $8 million between 2013 and 2012. The improvement was primarily due to increases in operating margin and other income and a decrease in net interest deductions, partially offset by higher operating expenses.

Operating margin increased $22 million between years. Rate relief provided $8 million of the increase in operating margin (including general rate relief in Nevada and net attrition amounts in California). New customers contributed $7 million of the increase during 2013 as approximately 28,000 net new customers were added during the last twelve months. Incremental margin from customers outside the decoupling mechanisms and other miscellaneous revenues (including amounts associated with recoveries of Arizona regulatory assets) contributed the remainder of the increase.

Operations and maintenance expense increased $14.9 million, or 4%, between years primarily due to higher general costs, employee-related costs (including a majority of the $6.4 million increase in pension costs), uncollectible expense, and pipeline integrity management programs, partially offset by lower legal claims and expenses.

Depreciation and amortization expense increased $7.8 million, or 4%. Average gas plant in service for the current year increased $230 million, or 5%, as compared to the prior year. This was attributable to pipeline capacity reinforcement work, franchise requirements, scheduled and accelerated pipe replacement activities, and new business. Increases in depreciation from these plant additions were partially offset by lower depreciation rates in Nevada (effective November 2012). Amortization associated with the recovery of Arizona regulatory assets, new conservation and energy efficiency programs in Nevada, and other amortization collectively increased $6.2 million.

Taxes other than income taxes increased $3.8 million between periods due to higher property taxes in Arizona and changes resulting from the last Nevada general rate case, whereby modified business and mill taxes became components of operating expenses.

Other income, which principally includes returns on COLI policies (including recognized net death benefits) and non-utility expenses, increased $8.1 million between 2013 and 2012. The current year reflects $12.4 million of COLI policy cash surrender value increases including net death benefits recognized, while the prior year included $6.6 million of COLI-related income. In addition, Arizona non-recoverable pipe replacement costs were $2.5 million lower in 2013 as compared to 2012 because this pipe replacement activity was substantially completed in 2012.

Net interest deductions decreased $4.4 million between 2013 and 2012 primarily due to cost savings from debt refinancing, redemptions, and lower interest expense associated with deferred PGA balances payable. The decrease was partially offset by the October 2013 issuance of $250 million of 4.875% senior notes. The prior year included a temporary increase in debt outstanding for approximately two months associated with debt refinancing that occurred in the first half of 2012.

2012 vs. 2011

Contribution to consolidated net income from natural gas operations increased by $25 million between 2012 and 2011. The improvement was primarily due to increases in operating margin and other income, partially offset by higher operating expenses.

Operating margin increased $52 million between years. Rate relief in Arizona ($45 million) and Nevada ($2 million) provided $47 million of the increase in operating margin. New customers contributed the remaining $5 million increase in operating margin during 2012. A $4 million increase between years, due to an adjustment (related to a regulatory deferral mechanism) that decreased operating margin in 2011, was offset by a reduction of $4 million in operating margin between years, primarily due to moderately cold weather experienced in Arizona in the first half of 2011. With a new rate decoupling mechanism in Arizona, effective January 2012, weather is no longer a significant factor in operating margin overall.

Operations and maintenance expense increased $11.5 million, or 3%, between years primarily due to higher general costs and employee-related costs including approximately $6 million of net pension expense, and to approximately $1 million in leak survey costs associated with a special Arizona program (see *Customer-Owned Yardline ("COYL") Program* in the **Rates and Regulatory Proceedings** section).

Depreciation expense increased $10.8 million, or 6%, as a result of additional plant in service. Average gas plant in service for 2012 increased $247 million, or 5%, compared to 2011. This was attributable to pipeline capacity reinforcement work, franchise requirements, scheduled and accelerated pipe replacement activities, and to a lesser degree, new business. The increase was partially offset by approximately $1 million due to a reduction in depreciation rates in Nevada, which became effective in November 2012.

Other income increased $9.6 million between 2012 and 2011. Cash surrender values of COLI policies increased $6.6 million in 2012, while COLI-related income (resulting from recognized death benefits net of decreases in cash surrender values) was $700,000 in the prior year. COLI income in 2012 was especially high due to strong equity-market returns on investments underlying the policies. In addition, Arizona non-recoverable pipe replacement and other non-utility costs were lower in 2012, especially during the fourth quarter, as compared to 2011. The non-recoverable portion of this pipe replacement activity was substantially completed in 2012.

Net interest deductions decreased $1.8 million between 2012 and 2011 primarily due to cost savings from refinancing, partially offset by a temporary increase in debt outstanding for approximately two months associated with the issuance of $250 million of 3.875% senior notes in March 2012 to repay $200 million of 7.625% senior notes that matured in May 2012, and by additional interest on variable-rate IDRBs.

Outlook for 2014

Operating margin for 2014 is expected to be favorably influenced by customer growth similar to 2013, as well as incremental margin associated with an expected California rate case decision (see **Rates and Regulatory Proceedings**).

Operating expenses for 2014 compared to 2013 will continue to be impacted by inflation, general cost increases, and depreciation expense on plant additions. Incremental costs, including higher property and general taxes, offset by a $9 million decrease in pension costs (approximately $7 million to be reflected in operations and maintenance expense), are expected to result in an overall operating expense increase of approximately 2% to 3%.

COLI-related income of $12.4 million in 2013 is significantly in excess of expected average returns and is not sustainable at these levels. Southwest expects longer term normal changes in COLI cash surrender values to range from $3 million to $5 million on an annual basis. However, individual quarterly and annual periods will continue to be subject to volatility.

Southwest anticipates an approximate $5 million to $6 million increase in net interest deductions in 2014 compared to 2013 primarily due to the October 2013 issuance of $250 million of 4.875% senior notes, partially offset by interest savings associated with the redemptions that occurred during 2013.

Infrastructure tracker mechanisms in Nevada and Arizona will contribute modestly to 2014 operating results and trend upward over the next several years.

Results of Construction Services

Year Ended December 31,	2013	2012	2011
(Thousands of dollars)			
Construction revenues	$650,628	$606,050	$483,822
Operating expenses:			
Construction expenses	573,284	541,523	423,703
Depreciation and amortization	42,969	37,387	25,216
Operating income	34,375	27,140	34,903
Other income (deductions)	39	246	(8)
Net interest deductions	1,145	1,063	825
Income before income taxes	33,269	26,323	34,070
Income tax expense	12,565	10,303	13,727
Net income	20,704	16,020	20,343
Net income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Contribution to consolidated net income attributable to NPL	$ 21,151	$ 16,712	$ 20,867

2013 vs. 2012

Contribution to consolidated net income from construction services for 2013 increased $4.4 million compared to 2012. The increase was primarily due to a $15 million pretax loss recognized on a large fixed-price contract in 2012, partially offset by lower gains on the sale of equipment and higher general and administrative expenses (included in Construction expenses) in 2013.

Revenues increased $44.6 million, or 7%, when compared to 2012 due primarily to an increase in utility customer contracts for pipe replacement work, partially offset by the winding down of a portion of work related to the large fixed-price contract noted above. Construction revenues include NPL contracts with Southwest totaling $88.2 million in 2013 and $83.4 million in 2012. NPL accounts for services provided to Southwest at contractual (market) prices at contract inception.

Construction expenses increased $31.8 million, or 6%, primarily due to additional pipe replacement work in 2013. Despite these increases, the construction expense variance between years was favorably impacted as the prior year included a $15 million pretax loss associated with the above-noted large fixed-price contract. This fixed-price contract is substantially complete. General and administrative expense (included in construction expenses) increased approximately $6 million due to changes that were implemented to match NPL's increased size and business complexity. In addition, NPL recorded approximately $4 million in 2013 associated with a legal settlement relating to former employees; no similar matters are pending. Depreciation expense increased $5.6 million between the current year and the prior year due to additional equipment purchased to support growth in the volume of work being performed. Gains on sale of equipment (reflected as an offset to construction expenses) were $4.1 million and $8 million in 2013 and 2012, respectively.

During the past several years, NPL has focused its efforts on obtaining pipe replacement work under both blanket contracts and incremental bid projects. In 2013, NPL experienced a slight increase in the volume of new construction installations. For 2013 and 2012, revenues from replacement work were 70% and 75%, respectively, of total revenues. Federal and state pipeline safety-related programs and bonus depreciation incentives have resulted in many utilities undertaking multi-year distribution pipe replacement projects. NPL continues to successfully bid on pipe replacement projects throughout the country.

2012 vs. 2011

Contribution to consolidated net income from construction services for 2012 decreased $4.2 million compared to 2011. The decline was primarily due to a loss on a large fixed-price contract in 2012, partially offset by additional replacement work and increased gains on sale of equipment.

Revenues increased $122 million, or 25%, when compared to 2011 due primarily to an increase in the volume of replacement work. Construction revenues included NPL contracts with Southwest totaling $83.4 million in 2012 and $92.1 million in 2011. NPL accounts for services provided to Southwest at contractual (market) prices at contract inception.

Construction expenses increased $118 million, or 28%, due to an increase in replacement construction work and a $15 million pretax loss on a large fixed-price contract. Depreciation expense increased $12.2 million between 2012 and 2011 due to an increase in equipment purchases. Gains on sale of equipment, included in construction expenses, were $8 million and $3.3 million in 2012 and 2011, respectively.

Outlook for 2014

NPL's revenues and operating profits are influenced by weather, customer requirements, mix of work, local economic conditions, bidding results, the equipment resale market, and the credit market. Typically, revenues are lowest during the first quarter of the year due to unfavorable winter weather conditions. Revenues typically improve as more favorable weather conditions occur during the summer and fall months. The current low interest rate environment, and the regulatory environment (encouraging the natural gas industry to replace aging pipeline infrastructure) are having a positive influence on NPL's results.

Management has an improved infrastructure in place on which to grow the business and is seeking to increase revenues by approximately 5% to 8% on average over the long term. Ultimately, revenues are subject to the timing and amount of work awarded to NPL by its utility customers. Extreme winter weather conditions during January and February 2014 have hindered normal construction work in most of the operating areas, with the exception of the Southwest. It is too early to predict if this will impact revenues for the full year. Overall, operating expenses are expected to increase in proportion to the growth in revenue.

Rates and Regulatory Proceedings

General Rate Relief and Rate Design

Rates charged to customers vary according to customer class and rate jurisdiction and are set by the individual state and federal regulatory commissions that govern Southwest's service territories. Southwest makes periodic filings for rate adjustments as the costs of providing service (including the cost of natural gas purchased) change, and as additional investments in new or replacement pipeline and related facilities are made. Rates are intended to provide for recovery of all prudently incurred costs and provide a reasonable return on investment. The mix of fixed and variable components in rates assigned to various customer classes (rate design) can significantly impact the operating margin actually realized by Southwest. Management has worked with its regulatory commissions in designing rate structures that strive to provide affordable and reliable service to its customers while mitigating the volatility in prices to customers and stabilizing returns to investors. Such rate structures were in place in all of Southwest's operating areas during 2012 and 2013.

Nevada General Rate Case. In the fourth quarter of 2012, a decision was reached at a public hearing (the "Decision") in the general rate application Southwest filed with the Public Utilities Commission of Nevada ("PUCN"), with rates effective November 2012. The Decision provided an annual revenue increase of $5.8 million in southern Nevada based on an overall rate of return of 6.49% and a 9.85% return on 42.6% common equity on original cost rate base of $825 million. For northern Nevada, the Decision provided a revenue increase of $1.2 million with an overall rate of return of 8.01% and a 9.20% return on 65.6% common equity on original cost rate base of $116 million. The Decision also included a reduction in annualized depreciation expense of $5.2 million and $1.7 million in southern and northern Nevada, respectively. In addition, the Decision reclassified approximately $2.5 million of modified business and mill taxes from pass-through items to operating expenses. On a combined basis, the Decision was expected to increase annual operating income by $11.4 million.

Following the Decision, the Company filed a Petition for Reconsideration requesting reconsideration of the findings in the Decision relating to the capital structure and other cost of service issues. In March 2013, the PUCN reached a decision in the rehearing (the "Rehearing Decision") relating to the capital structure issue. The Rehearing Decision retained an alternative capital structure, as opposed to utilizing Southwest's proposed capital structure, and authorized an overall rate of return of 6.56% and a 10.0% return on 42.7% common equity in southern Nevada and an overall rate of return of 7.88% and a 9.30% return on 59.1% common equity in northern Nevada. When compared to the original Decision, the Rehearing Decision is expected to result in an annual revenue increase of $1.0 million in southern Nevada and an annual revenue decrease of $0.5 million in northern Nevada.

Nevada Infrastructure Replacement Mechanisms. As part of the Nevada general rate case application in April 2012, Southwest requested to implement an infrastructure replacement mechanism to defer and recover certain costs associated with up to $40 million annually of proposed accelerated replacement of early vintage plastic ("EVPP") and steel pipe. As part of its fourth quarter 2012 decision, the PUCN indicated a separate rulemaking docket would be needed to address the regulatory issues necessary to implement such a mechanism. In January 2013, the PUCN authorized the opening of a new docket to review the merits of such mechanisms. An initial round of comments and reply comments were submitted and a workshop on the matter was convened. The scope of the rulemaking was expanded in order to consider additional forms of recovery mechanisms. In July, the Administrative Law Judge in the docket forwarded a draft regulation to the Nevada Legislative Counsel Bureau ("LCB") for review. The draft regulation provided for the establishment of regulatory assets that recover the depreciation expense and authorized pre-tax rate of return of infrastructure replacement investments in between rate cases. Southwest would then be able to develop rates to recover the associated amounts in a future general rate case proceeding, at which time the plant would be "rolled into" rate base naturally. The LCB proposed slight modifications to the regulation and returned it to the PUCN in August. In January 2014, the PUCN concluded the rulemaking process by approving final rules.

Separately, in March 2013, Southwest submitted a petition to the PUCN requesting authority to defer certain costs associated with the proposed accelerated 2013 replacement of certain EVPP to coincide with bonus depreciation tax relief extended by The American Taxpayer Relief Act of 2012. In June 2013, a stipulation (the "Stipulation"), which provided regulatory asset treatment for specific infrastructure replacement projects occurring during 2013 in the amount of $2 million in northern Nevada and approximately $13.6 million in southern Nevada, was reached by all parties and was approved by the PUCN. While the above-noted infrastructure replacement regulation was being finalized, the Company submitted a filing to the PUCN in November 2013 requesting authority to replace $18.9 million of EVPP in 2014; the PUCN approved the request in January 2014. The new rules (noted above) will additionally enable the Company to make a filing in 2014 identifying projects that Southwest proposes to be replaced beginning in January 2015.

Effectively, as a result of these mechanisms, the increase in depreciation expense, ordinarily arising from related capital expenditures, will be netted to zero by the deferral process. Incremental operating margin associated with these infrastructure replacements will materialize after the PUCN authorizes a surcharge, anticipated to commence during the first quarter of 2016.

California Annual Attrition. As part of the 2009 rate decision by the California Public Utilities Commission ("CPUC") in Southwest's last California general rate case, attrition increases were authorized for the years 2010-2013. The level of increase authorized for 2013 was $1.8 million in southern California, $500,000 in northern California, and $100,000 in South Lake Tahoe. However, the continued low interest rate environment triggered an automatic rate of return adjustment mechanism (or Automatic Trigger Mechanism), which resulted in offsetting decreases of $700,000 in southern California, $500,000 in northern California, and $100,000 in South Lake Tahoe. The resulting net margin impact for the California rate jurisdictions was an overall increase of $1.1 million in 2013.

California General Rate Case. In December 2012, Southwest filed a general rate case application with the CPUC requesting annual revenue increases of $5.6 million for southern California, $3.2 million for northern California, and $2.8 million for the South Lake Tahoe rate jurisdiction. The application includes a capital structure consisting of 43% debt and 57% common equity and a return on equity of 10.7%, with an overall rate of return of 7.32% in southern California and 8.61% in both northern California and South Lake Tahoe. Southwest is also seeking to continue a Post-Test Year Ratemaking Mechanism, which allows for annual attrition increases. The application includes the addition of an Infrastructure Reliability and Replacement Adjustment Mechanism ("IRRAM") to facilitate and complement projects involving the enhancement and replacement of gas infrastructure, promoting timely cost recovery for qualifying non-revenue producing capital expenditures. A proposed decision was issued by the administrative law judge and includes a total overall revenue increase of approximately $7.5 million, a capital structure consisting of 45% debt and 55% equity and a return on equity of 10.1%, acceptance of Company-proposed changes to the Automatic Trigger Mechanism, and approval of the IRRAM, including a Customer-Owned Yardline Program. The proposed decision is expected to be voted on by the CPUC in the first quarter of 2014.

Arizona Decoupling Mechanism. In December 2011, the Arizona Corporation Commission ("ACC") approved a settlement (effective January 2012) associated with Southwest's general rate application in November 2010. The settlement approved a revenue increase of $52.6 million with a return on equity of 9.50%. The settlement also approved a full revenue decoupling mechanism and a monthly weather adjustor. For 2012, the weather adjustor resulted in approximately $18 million being added to customer bills to offset warmer-than-normal temperatures, while in 2013 nearly $12 million was subtracted from customer bills to offset colder-than-normal temperatures. In addition, during 2012 the Company recorded a net $2 million payable to customers associated with the margin tracking deferral mechanism (the corresponding payable for 2013 was approximately $10 million). The ACC Staff recently completed a review of the decoupling mechanism (and a related report) for 2012. The ACC Staff found the mechanism to be working as designed and recommended its continuation. The ACC approved the decoupling report in December 2013 and authorized the Company to refund the over-collected balance that existed at December 31, 2012.

Customer-Owned Yardline ("COYL") Program. The Company received approval, in connection with its most recent Arizona general rate case, to implement a program to conduct leak surveys, and if leaks were present, to replace and relocate service lines and meters for approximately 100,000 Arizona customers whose meters are set-off from the customer's home, which is not a traditional configuration. Customers with this configuration were previously responsible for the cost of maintaining these lines and were subject to the immediate cessation of natural gas service if low-pressure leaks occurred. To facilitate this program, the Company was authorized to collect estimated leak survey costs in rates commencing in 2012. Effective June 2013, the ACC authorized a surcharge of $0.00101 per therm (approximately $600,000 annually) to recover the costs of depreciation and pre-tax return the Company would have received if the additional pipe replacement costs themselves (approximately $4 million through December 2012) had been included in rate base concurrent with the most recent Arizona rate case. (During 2013, approximately $6 million in additional COYL-related pipe replacement costs were added to plant.) The surcharge is expected to be revised annually as the program progresses, with the undepreciated plant balance to be incorporated in base rates at the time of the next Arizona general rate case. Management has not determined the timing of filing its next general rate case in Arizona; however, Southwest agreed in the settlement in its most recent Arizona general rate case filing to not file a general rate case in Arizona until April 30, 2016. In November 2013, the Company filed a request to modify or clarify the COYL provision to add a "Phase II" component to the COYL program to include the replacement of non-leaking COYLs. This request was approved by the ACC in January 2014, and requires that these replacements are coordinated with the Company's other pipeline replacement projects and that the Company will prioritize leaking COYLs over non-leaking COYLs. The revised surcharge request is expected to be filed in February 2014 with a proposed effective date of June 2014. Approximately 85% of COYLs were tested through December 2013 with nearly 4,000 relocations completed.

Proposed LNG Facility. In January 2014, Southwest filed an application with the ACC seeking preapproval to construct, operate and maintain a 233,000 dekatherm LNG facility in southern Arizona and to recover the actual costs, including the establishment of a regulatory asset. The LNG facility is designed to enhance service reliability and flexibility in natural gas deliveries in the southern Arizona area. Southwest requested approval of the actual cost of the project (including those facilities necessary to connect the proposed storage tank to Southwest's existing distribution system) not to exceed $55 million. The proposed LNG facility would provide a local storage option, operated by Southwest and connected directly to its distribution system, providing greater flexibility to serve customers. An ACC decision is expected to occur during 2014. If approved, construction is expected to be complete within approximately 24 to 30 months after ACC approval.

Federal Energy Regulatory Commission ("FERC") Jurisdiction. During the third quarter of 2013, Paiute Pipeline Company, a wholly owned subsidiary of Southwest, notified present and potential shippers of its plans to expand its existing transmission system to provide additional firm transportation-service capacity in the Elko County, Nevada area. This additional capacity is required to meet growing natural gas demands caused by increased residential and business load and the greater energy needs of mining operations in the area. Through the "open season" process, shippers responded with substantial interest. Dependent upon several variables, including the ultimate route of the project, the price of materials, and factors such as environmental impacts, the cost to complete this project has been estimated at approximately $35 million and has a targeted in-service date of November 2015. In October 2013, Paiute submitted a filing with the FERC requesting that its Staff initiate a pre-filing review of the proposed expansion project; a comprehensive application for the project is expected to follow completion of the pre-filing review.

Paiute Pipeline Company will file a general rate case with the FERC by the end of February 2014. The filing will fulfill an obligation from the settlement agreement reached in the 2009 Paiute general rate case. The application is expected to request an increase in operating revenues of approximately $9 million. In accordance with FERC requirements, new rates will go into effect in September 2014, subject to refund, if a settlement among the parties has not been approved by the FERC by that time. Paiute's most recent general rate case was filed in 2009.

PGA Filings

The rate schedules in all of Southwest's service territories contain provisions that permit adjustments to rates as the cost of purchased gas changes. These deferred energy provisions and purchased gas adjustment clauses are collectively referred to as "PGA" clauses. Differences between gas costs recovered from customers and amounts paid for gas by Southwest result in over- or under-collections. At December 31, 2013, under-collections in all three states resulted in an asset of $18.2 million on the Company's balance sheet. Filings to change rates in accordance with PGA clauses are subject to audit by state regulatory commission staffs.

PGA changes impact cash flows but have no direct impact on profit margin. However, gas cost deferrals and recoveries can impact comparisons between periods of individual income statement components. These include Gas operating revenues, Net cost of gas sold, Net interest deductions, and Other income (deductions).

Southwest had the following outstanding PGA balances receivable/(payable) at the end of its two most recent fiscal years (millions of dollars):

	2013	2012
Arizona	$ 3.2	$(46.6)
Northern Nevada	4.4	(7.1)
Southern Nevada	4.1	(45.2)
California	6.5	6.0
	$18.2	$(92.9)

Arizona PGA Filings. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits measured on a twelve-month rolling average. A temporary surcredit of $0.08 per therm was put into place in December 2009 to help accelerate the refund of the over-collected balance to customers. In order to accelerate the refunds to customers, Southwest filed to temporarily increase this rate to $0.10 per therm effective January 2013, which was approved by the ACC in December 2012. During 2013, approximately $49 million was refunded to customers via the surcredit. The temporary surcredits were eliminated in January 2014. A prudence review of gas costs is conducted in conjunction with general rate cases.

California Gas Cost Filings. In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized. Monthly adjustments modeled in this fashion provide the timeliest recovery of gas costs in any Southwest jurisdiction and are designed to send appropriate pricing signals to customers.

Nevada Annual Rate Adjustment ("ARA") Application. In June 2013, Southwest filed its ARA application with the PUCN to establish revised Deferred Energy Account Adjustment ("DEAA") rates (in addition to adjustments to the Variable Interest Expense rate, the Uncollectible Gas Cost Expense rates, and other rate-related items), which was approved effective January 2014. As part of the most recent ARA and associated stipulation in Nevada, the Company, at least in the short term, agreed to suspend further fixed-for-floating swap contracts ("Swaps") and fixed-price purchases pursuant to the Volatility Mitigation Program ("VMP") for its Nevada service territories. The decision will not impact previously executed purchase arrangements. The Company along with its regulators will continue to evaluate this strategy in light of prevailing or anticipated changing market conditions. Southwest makes quarterly DEAA adjustments based upon a twelve-month rolling average. During 2013, approximately $51 million was refunded to customers via billing credits. See *Gas Price Volatility Mitigation* below for information on the Company's Swaps.

Gas Price Volatility Mitigation

Regulators in Southwest's service territories have encouraged Southwest to take proactive steps to mitigate price volatility to its customers. To accomplish this, Southwest periodically enters into fixed-price term contracts and Swaps under its collective volatility mitigation programs for a portion (for the 2013/2014 heating season, ranging from 25% to 35%, depending on the jurisdiction) of its annual normal weather supply needs. For the 2013/2014 heating season, contracts contained in the fixed-price portion of the portfolio included pricing of approximately $4 per dekatherm. Natural gas purchases not covered by fixed-price contracts are made under variable-price contracts with firm quantities, and on the spot market. Prices for these contracts are not known until the month of purchase. As noted above, the VMP in Nevada has been suspended and is subject to future evaluation given changing market conditions.

Capital Resources and Liquidity

Over the past three years, cash on hand and cash flows from operations have generally provided the majority of cash used in investing activities (primarily construction expenditures and property additions). Certain pipe replacement work was accelerated during 2011, 2012, and 2013 to take advantage of bonus depreciation tax incentives and to fortify system integrity and reliability. Tax incentives have not been extended for years after 2013. During the same three-year period, the Company was able to achieve cost savings from debt refinancing and strategic debt redemptions. The Company's capitalization strategy is to maintain an appropriate balance of equity and debt to maintain strong investment-grade credit ratings which should minimize interest costs.

Cash Flows

Operating Cash Flows. Cash flows provided by consolidated operating activities decreased $40.1 million in 2013 as compared to 2012. The decline in operating cash flows was attributable to temporary decreases in cash flows from working capital components overall (notably, refunds of PGA balances), partially offset by higher net income and non-cash depreciation expense.

Investing Cash Flows. Cash used in consolidated investing activities decreased $26 million in 2013 as compared to 2012. The decrease was primarily due to reduced equipment purchases by NPL.

Financing Cash Flows. Net cash provided by consolidated financing activities increased $26.1 million in 2013 as compared to 2012. The increase was primarily due to the 2012 $21.8 million settlement (at maturity) of the second FSIRS contract. In addition, cash provided by debt financing (net of retirements and credit facility changes) increased in 2013 as compared to 2012. The current year includes issuance of $250 million of 4.875% senior notes, partially offset by the repayment of $30 million of 5.45% IDRBs, $15 million of 5.8% of IDRBs, $8.27 million of 5.55% IDRBs, and the repayment of outstanding borrowings on the credit facility. The prior-year period included debt repayments of the $12.4 million 1999 6.1% Series A fixed-rate IDRBs (repaid in January 2012), the $200 million 7.625% senior notes (repaid in May 2012), the $14.3 million 1999 5.95% Series C fixed-rate IDRBs (repaid in August 2012). Those repayments were partially offset by the issuance of new debt in the prior-year period, including the $250 million of 3.875% senior notes and borrowings under the long-term portion of the credit facility. The remaining issuance amounts and retirements of long-term debt in both years primarily relate to borrowings and repayments under NPL's line of credit, and in 2013, borrowing under note agreements with two banking institutions (entered into during the second quarter of 2013). Dividends paid increased in 2013 as compared to 2012 as a result of an increase in the quarterly dividend rate and an increase in the number of shares outstanding.

The capital requirements and resources of the Company generally are determined independently for the natural gas operations and construction services segments. Each business activity is generally responsible for securing its own financing sources.

2013 Construction Expenditures

During the three-year period ended December 31, 2013, total gas plant increased from $4.6 billion to $5.3 billion, or at an average annual rate of 5%. Replacement, reinforcement, and franchise work was a substantial portion of the plant increase. To a lesser extent, customer growth impacted expenditures as the Company set approximately 51,000 meters during the three-year period.

During 2013, construction expenditures for the natural gas operations segment were $315 million. The majority of these expenditures represented costs associated with scheduled and accelerated replacement of existing transmission, distribution, and general plant to fortify system integrity and reliability and to take advantage of certain tax incentives (see also *Bonus Depreciation* below). Cash flows from operating activities of Southwest were $265 million and provided approximately 70% of construction expenditures and dividend requirements of the natural gas operations segment. Other necessary funding was provided by cash on hand, external financing activities, and, as needed, existing credit facilities.

2013 Financing Activity

In March 2013, the Company redeemed at par its $30 million 2003 5.45% Series C IDRBs and $15 million 2003 5.8% Series E IDRBs. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

During 2013, the Company issued shares of common stock through its various stock plans, including the Stock Incentive Plan, raising approximately $1.6 million.

Bonus Depreciation. In January 2013, the American Taxpayer Relief Act of 2012 ("Taxpayer Relief Act") was enacted extending the 50% bonus tax depreciation deduction provided for by earlier legislation for qualified property acquired or constructed and placed in-service during 2013. This tax deduction was not extended for years after 2013. Based on forecasted qualifying construction expenditures, Southwest estimates the bonus depreciation provision of the Taxpayer Relief Act deferred the payment of approximately $26 million of federal income taxes for 2013.

Three-Year Construction Expenditures, Debt Maturities, and Financing

Southwest estimates natural gas segment construction expenditures during the three-year period ending December 31, 2016 will be approximately $1.1 billion. Of this amount, approximately $375 million are expected to be incurred in 2014. Southwest plans to accelerate projects that improve system flexibility and reliability (including replacement of early vintage plastic and steel pipe). Significant replacement activities are expected to continue during the next several years. See also **Rates**

and Regulatory Proceedings for discussion of Nevada infrastructure, California IRRAM, Arizona COYL, a planned LNG facility, and planned Paiute expansion. During the three-year period, cash flows from operating activities of Southwest are expected to provide approximately 85% of the funding for the gas operations total construction expenditures and dividend requirements. Any additional cash requirements are expected to be provided by existing credit facilities and/or other external financing sources. The timing, types, and amounts of any additional external financings will be dependent on a number of factors, including the cost of gas purchases, conditions in the capital markets, timing and amounts of rate relief, growth levels in Southwest's service areas, and earnings. External financings could include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

Liquidity

Liquidity refers to the ability of an enterprise to generate sufficient amounts of cash through its operating activities and external financings to meet its cash requirements. Several general factors (some of which are out of the control of the Company) that could significantly affect liquidity in future years include: variability of natural gas prices, changes in the ratemaking policies of regulatory commissions, regulatory lag, customer growth in the natural gas segment's service territories, Southwest's ability to access and obtain capital from external sources, interest rates, changes in income tax laws, pension funding requirements, inflation, and the level of Company earnings. Natural gas prices and related gas cost recovery rates have historically had the most significant impact on Company liquidity.

On an interim basis, Southwest defers over- or under-collections of gas costs to PGA balancing accounts. In addition, Southwest uses this mechanism to either refund amounts over-collected or recoup amounts under-collected as compared to the price paid for natural gas during the period since the last PGA rate change went into effect. During 2013, refunds were made to customers and the net over-collected PGA balance declined $111 million resulting in an under-collection of $18.2 million at December 31, 2013. See **PGA Filings** for more information.

The Company has a $300 million revolving credit facility that expires in March 2017. Southwest has designated $150 million of the $300 million facility for long-term borrowing needs and the remaining $150 million for working capital purposes. The maximum amount outstanding during 2013 was $195 million ($150 million outstanding on the long-term portion of the credit facility (including $50 million on the commercial paper program), and $45 million outstanding on the short-term portion) in the fourth quarter. At December 31, 2013, $10 million was outstanding on the long-term portion of the credit facility (all of which was under the commercial paper program), and no borrowings were outstanding on the short-term portion. The maximum amount outstanding on the credit facility (including the commercial paper program) during the first, second, and third quarters was $152 million, $125 million, and $183 million, respectively. The credit facility can be used as necessary to meet liquidity requirements, including temporarily financing under-collected PGA balances, if any, meeting the refund needs of over-collected balances, or temporarily funding capital expenditures. This credit facility has been, and is expected to continue to be, adequate for Southwest's working capital needs outside of funds raised through operations and other types of external financing.

The Company has a $50 million commercial paper program. Any issuance under the commercial paper program is supported by the Company's current revolving credit facility and, therefore, does not represent additional borrowing capacity. Any borrowing under the commercial paper program will be designated as long-term debt. Interest rates for the commercial paper program are calculated at the then current commercial paper rate. At December 31, 2013, $10 million were outstanding on the commercial paper program. The maximum amount outstanding during the year was $50 million.

NPL has a $75 million credit facility that is scheduled to expire in June 2015. At December 31, 2013, no borrowings were outstanding on the NPL credit facility.

Credit Ratings
The Company's borrowing costs and ability to raise funds are directly impacted by its credit ratings. Securities ratings issued by nationally recognized ratings agencies provide a method for determining the credit worthiness of an issuer. Company debt ratings are important because long-term debt constitutes a significant portion of total capitalization. These debt ratings are a factor considered by lenders when determining the cost of debt for the Company (i.e., generally the better the rating, the lower the cost to borrow funds).

In March 2013, Standard & Poor's Ratings Services ("S&P") upgraded the Company's unsecured long-term debt ratings from BBB+ (with a stable outlook) to A− (with a stable outlook). S&P cited the Company's sustained improvements in cash flow and leverage measures and improved regulatory relationships in all three service territories. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of A− indicates the issuer of the debt is regarded as having a strong capacity to meet financial commitments.

In May 2013, Fitch Ratings ("Fitch") upgraded the Company's senior unsecured ratings including IDRBs from A− (with a positive outlook) to A (with a stable outlook). Fitch cited the Company's stronger credit metrics and improved business risk profile. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of A indicates low default risk and a strong ability to pay financial commitments.

In January 2014, Moody's Investors Service, Inc. ("Moody's") upgraded the Company's senior unsecured ratings from Baa1 with a stable outlook to A3 with a stable outlook. Moody's cited the Company's improved regulatory environment in its service territories. Moody's debt ratings range from Aaa (highest rating possible) to C (lowest quality, usually in default). Moody's applies an A rating to obligations which are considered upper-medium grade obligations with low credit risk. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the A to indicate the approximate rank of a company within the range.

A securities rating is not a recommendation to buy, sell, or hold a security and is subject to change or withdrawal at any time by the rating agency. The foregoing securities ratings are subject to change at any time in the discretion of the applicable ratings agencies. Numerous factors, including many that are not within the Company's control, are considered by the ratings agencies in connection with assigning securities ratings.

No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain securities ratings covenants that, if set in motion, would increase financing costs if debt ratings deteriorated. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2013, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.9 billion in additional debt and meet the leverage ratio requirement. The Company has at least $800 million of cushion in equity relating to the minimum net worth requirement.

Inflation
Inflation can impact the Company's results of operations. Natural gas, labor, employee benefits, consulting, and construction costs are the categories most significantly impacted by inflation. Changes to the cost of gas are generally recovered through PGA mechanisms and do not significantly impact net earnings. Labor and employee benefits are components of the cost of service, and construction costs are the primary component of rate base. In order to recover increased costs, and earn a fair return on rate base, general rate cases are filed by Southwest, when deemed necessary, for review and approval by regulatory authorities. Regulatory lag, that is, the time between the date increased costs are incurred and the time such increases are recovered through the ratemaking process, can impact earnings. See **Rates and Regulatory Proceedings** for a discussion of recent rate case proceedings.

Off-Balance Sheet Arrangements

All Company debt is recorded on its balance sheets. The Company has long-term operating leases, which are described in **Note 2 – Utility Plant** of the Notes to Consolidated Financial Statements, and included in the Contractual Obligations Table below.

Contractual Obligations

The Company has various contractual obligations such as long-term purchase contracts, significant non-cancelable operating leases, gas purchase obligations, and long-term debt agreements. The Company has classified these contractual obligations as either operating activities or financing activities, which mirrors their presentation in the Consolidated Statement of Cash Flows. No contractual obligations for investing activities exist at this time. The table below summarizes the Company's contractual obligations at December 31, 2013 (millions of dollars):

	Payments due by period				
Contractual Obligations	Total	2014	2015-2016	2017-2018	Thereafter
Operating activities:					
Operating leases (Note 2)	$ 21	$ 7	$ 10	$ 3	$ 1
Gas purchase obligations	163	122	41	—	—
Pipeline capacity/storage	776	99	156	103	418
Other commitments	20	9	10	1	—
Financing activities:					
Long-term debt, including current maturities (Note 6)	1,392	11	21	45	1,315
Interest on long-term debt	1,134	63	125	120	826
Other	10	—	1	1	8
Total	$3,516	$311	$364	$273	$2,568

Obligations for Operating Activities: The table above provides a summary of the Company's obligations associated with operating activities. Operating leases represent multi-year obligations for office rent and certain equipment. Gas purchase obligations include fixed-price and variable-rate gas purchase contracts covering approximately 139 million dekatherms. The fixed-price contracts have an approximate price of $4 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

Southwest has pipeline capacity/storage contracts for firm transportation service, both on a short- and long-term basis, with several companies for all of its service territories, some with terms extending to 2044. Southwest also has interruptible contracts in place that allow additional capacity to be acquired should an unforeseen need arise. Costs associated with these pipeline capacity contracts are a component of the cost of gas sold and are recovered from customers primarily through the PGA mechanism. Included in the pipeline capacity payments shown in the above table, are payments associated with storage that Southwest has contracted for in southern California and Arizona. The terms of these contracts extend through 2024 and 2019, respectively.

Obligations for Financing Activities: Contractual obligations for financing activities are debt obligations consisting of scheduled principal and interest payments over the life of the debt. Interest rates in effect at December 31, 2013 on variable rate long-term debt were assumed to remain in effect in the future periods disclosed in the table.

Other: Estimated funding for pension and other postretirement benefits during calendar year 2014 is $36 million.

Application of Critical Accounting Policies

A critical accounting policy is one which is very important to the portrayal of the financial condition and results of a company, and requires the most difficult, subjective, or complex judgments of management. The need to make estimates about the effect of items that are uncertain is what makes these judgments difficult, subjective, and/or complex. Management makes subjective judgments about the accounting and regulatory treatment of many items and bases its estimates on historical experience and on various other assumptions that it believes to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained, and as the Company's operating environment changes. The following are accounting policies that are deemed critical to the financial statements of the Company. For more information regarding the significant accounting policies of the Company, see **Note 1 – Summary of Significant Accounting Policies**.

Regulatory Accounting

Natural gas operations are subject to the regulation of the Arizona Corporation Commission, the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission. The accounting policies of the Company conform to generally accepted accounting principles applicable to rate-regulated entities and reflect the effects of the ratemaking process. As such, the Company is allowed to defer as regulatory assets, costs that otherwise would be expensed, if it is probable that future recovery from customers will occur. The Company reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. If rate recovery is no longer probable, due to competition or the actions of regulators, the Company is required to write-off the related regulatory asset (which would be recognized as current-period expense). Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The timing and inclusion of costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings. Refer to **Note 4 – Regulatory Assets and Liabilities** for a list of regulatory assets and liabilities.

Accrued Utility Revenues

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of natural gas sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, margin associated with natural gas service that has been provided but not yet billed is accrued. This accrued utility revenue is estimated each month based primarily on applicable rates, number of customers, rate structure, analyses reflecting significant historical trends, seasonality, and experience. The interplay of these assumptions can impact the variability of the accrued utility revenue estimates. All Company rate jurisdictions have decoupled rate structures, limiting variability due to extreme weather conditions.

Accounting for Income Taxes

The income tax calculations of the Company require estimates due to known future tax rate changes, book to tax differences, and uncertainty with respect to regulatory treatment of certain property items. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Regulatory tax assets and liabilities are recorded to the extent the Company believes they will be recoverable from or refunded to customers in future rates. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The Company regularly assesses financial statement tax provisions to identify any change in the regulatory treatment or tax-related estimates, assumptions, or enacted tax rates that could have a material impact on cash flows, the financial position, and/or results of operations of the Company.

Accounting for Pensions and Other Postretirement Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees. In addition, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The Company's pension obligations and costs for these plans are affected by the amount and timing of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension obligations and costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions (particularly the discount rate) may significantly affect pension obligations and costs for these plans. For example, a change of 0.25% in the discount rate assumption would change the pension plan projected benefit obligation by approximately $30.6 million and future pension expense by $3.4 million. A change of 0.25% in the employee compensation assumption would change the pension obligation by approximately $7.4 million and expense by $1.6 million. A 0.25% change in the expected asset return assumption would change pension expense by approximately $1.7 million (but has no impact on the pension obligation).

At December 31, 2013, the Company raised the discount rate to 5.00% from a rate of 4.25% at December 31, 2012. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation escalation increased to 3.25% at December 31, 2013 from 2.75% in the prior year. The asset return assumption to be used for 2014 expense was reduced to 7.75% from 8.00%. The significant increase in the discount rate will decrease the expense level for 2014. Pension expense for 2014 is estimated to decrease by $9 million compared to 2013. Future years' expense level movements (up or down) will continue to be greatly influenced by long-term interest rates, asset returns, and funding levels.

Certifications

The Securities and Exchange Commission ("SEC") requires the Company to file certifications of its Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") regarding reporting accuracy, disclosure controls and procedures, and internal control over financial reporting as exhibits to the Company's periodic filings. The CEO and CFO certifications for the period ended December 31, 2013 are included as exhibits to the 2013 Annual Report on Form 10-K filed with the SEC.

Forward-Looking Statements

This annual report contains statements which constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995 ("Reform Act"). All statements other than statements of historical fact included or incorporated by reference in this annual report are forward-looking statements, including, without limitation, statements regarding the Company's plans, objectives, goals, intentions, projections, strategies, future events or performance, and underlying assumptions. The words "may," "if," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "project," "continue," "forecast," "intend," "promote," "seek," and similar words and expressions are generally used and intended to identify forward-looking statements. For example, statements regarding operating margin patterns, customer growth, the composition of our customer base, price volatility, seasonal patterns, payment of debt, interest savings, the Company's COLI strategy, annual COLI returns, replacement market and new construction market, bonus depreciation tax deductions, amount and timing for completion of estimated future construction expenditures, including the planned LNG facility in southern Arizona and the proposed Paiute expansion in Elko County, Nevada, forecasted operating cash flows and results of operations, incremental operating margin in 2014, operating expense increases in 2014, funding sources of cash requirements, sufficiency of working capital and current credit facility, bank lending practices, the Company's views regarding its liquidity position, ability to raise funds and receive external financing capacity, future dividend increases, earnings trends, NPL's projected financial performance and related market growth potential, pension and post-retirement benefits, certain benefits of tax acts, the effect of any rate changes or regulatory proceedings, including the Rehearing Decision and the Stipulation from the PUCN, the California general rate case filing, the Paiute Pipeline Company general rate case filing, infrastructure replacement mechanisms and the COYL program, statements regarding future gas prices, gas purchase contracts and derivative financial instruments, recoverability of regulatory assets, the impact of certain legal proceedings, and the timing and results of future rate hearings and approvals are forward-looking statements. All forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act.

A number of important factors affecting the business and financial results of the Company could cause actual results to differ materially from those stated in the forward-looking statements. These factors include, but are not limited to, customer growth rates, conditions in the housing market, the ability to recover costs through the PGA mechanisms or other regulatory assets, the effects of regulation/deregulation, the timing and amount of rate relief, changes in rate design, changes in gas procurement practices, changes in capital requirements and funding, the impact of conditions in the capital markets on financing costs, changes in construction expenditures and financing, changes in operations and maintenance expenses, effects of pension expense forecasts, accounting changes, future liability claims, changes in pipeline capacity for the transportation of gas and related costs, results of NPL bid work, impacts of structural and management changes at NPL, NPL construction expenses, differences between actual and originally expected outcomes of NPL bid or other fixed-price construction agreements, competition, and our ability to raise capital in external financings. In addition, the Company can provide no assurance that its discussions regarding certain trends relating to its financing and operating expenses will continue in future periods. For additional information on the risks associated with the Company's business, see **Item 1A. Risk Factors** and **Item 7A. Quantitative and Qualitative Disclosures About Market Risk** in the Company's Annual Report on Form 10-K for the year ended December 31, 2013.

All forward-looking statements in this annual report are made as of the date hereof, based on information available to the Company as of the date hereof, and the Company assumes no obligation to update or revise any of its forward-looking statements even if experience or future changes show that the indicated results or events will not be realized. **We caution you not to unduly rely on any forward-looking statement(s).**

Common Stock Price and Dividend Information

	2013		2012		Dividends Declared	
	High	Low	High	Low	2013	2012
First quarter	$48.11	$42.02	$43.64	$40.51	$0.330	$0.295
Second quarter	51.52	45.11	44.64	39.46	0.330	0.295
Third quarter	50.99	45.70	46.08	42.19	0.330	0.295
Fourth quarter	56.03	48.76	44.83	39.01	0.330	0.295
					$1.320	$1.180

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 18, 2014, there were 15,314 holders of record of common stock, and the market price of the common stock was $54.35.

In reviewing dividend policy, the Board of Directors ("Board") considers the adequacy and sustainability of earnings and cash flows of the Company and its subsidiaries; the strength of the Company's capital structure; the sustainability of the dividend through all business cycles; and whether the dividend is within a normal payout range for its respective businesses. The quarterly common stock dividend declared was 26.5 cents per share throughout 2011, 29.5 cents per share throughout 2012, and 33 cents per share throughout 2013. As a result of its ongoing review of dividend policy, in February 2014, the Board increased the quarterly dividend from 33 cents to 36.5 cents per share, effective with the June 2014 payment. This marks the eighth consecutive year in which the dividend was increased. Over time, the Board intends to increase the dividend such that the payout ratio approaches a local distribution company peer group average, while maintaining the Company’s stable and strong credit ratings and the ability to effectively fund future rate base growth. The timing and amount of any future increases will be based upon the Board’s continued review of the Company’s dividend rate in the context of the performance of the Company’s two operating segments and their future growth prospects.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Thousands of dollars, except par value)

December 31,	2013	2012
ASSETS		
Utility plant:		
Gas plant	$ 5,252,469	$ 5,019,500
Less: accumulated depreciation	(1,868,504)	(1,750,795)
Acquisition adjustments, net	730	911
Construction work in progress	101,413	74,178
Net utility plant (Note 2)	3,486,108	3,343,794
Other property and investments (Note 1)	260,871	242,096
Current assets:		
Cash and cash equivalents	41,077	25,530
Accounts receivable, net of allowances (Note 3)	219,469	196,913
Accrued utility revenue	72,700	72,000
Income taxes receivable, net	3,790	2,945
Deferred income taxes (Note 11)	31,130	47,088
Deferred purchased gas costs (Note 4)	18,217	6,031
Prepaids and other current assets (Notes 1, 4, and 12)	108,289	107,910
Total current assets	494,672	458,417
Deferred charges and other assets (Notes 4 and 12)	323,523	443,750
Total assets	$ 4,565,174	$ 4,488,057

CONSOLIDATED BALANCE SHEETS – Continued

December 31,	2013	2012
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized – 60,000,000 shares; issued and outstanding – 46,356,125 and 46,147,788 shares) (Note 10)	$ 47,986	$ 47,778
Additional paid-in capital	840,521	828,777
Accumulated other comprehensive income (loss), net (Note 5)	(41,698)	(50,745)
Retained earnings	567,714	484,369
Total Southwest Gas Corporation equity	1,414,523	1,310,179
Noncontrolling interest	(2,128)	(1,681)
Total equity	1,412,395	1,308,498
Long-term debt, less current maturities (Note 6)	1,381,327	1,268,373
Total capitalization	2,793,722	2,576,871
Commitments and contingencies (Note 8)		
Current liabilities:		
Current maturities of long-term debt (Note 6)	11,105	50,137
Accounts payable	183,511	155,667
Customer deposits	73,367	77,858
Accrued general taxes	39,681	37,644
Accrued interest	17,920	16,080
Deferred purchased gas costs (Note 4)	—	98,957
Other current liabilities (Notes 4 and 12)	108,580	98,786
Total current liabilities	434,164	535,129
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 11)	674,411	616,184
Taxes payable	284	551
Accumulated removal costs (Note 4)	279,000	256,000
Other deferred credits (Notes 4, 9, and 12)	383,593	503,322
Total deferred income taxes and other credits	1,337,288	1,376,057
Total capitalization and liabilities	$4,565,174	$4,488,057

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share amounts)

Year Ended December 31,	2013	2012	2011
Operating revenues:			
Gas operating revenues	$1,300,154	$1,321,728	$1,403,366
Construction revenues	650,628	606,050	483,822
Total operating revenues	1,950,782	1,927,778	1,887,188
Operating expenses:			
Net cost of gas sold	436,001	479,602	613,489
Operations and maintenance	384,914	369,979	358,498
Depreciation and amortization	236,817	223,422	200,469
Taxes other than income taxes	45,551	41,728	40,949
Construction expenses	573,284	541,523	423,703
Total operating expenses	1,676,567	1,656,254	1,637,108
Operating income	274,215	271,524	250,080
Other income and (expenses):			
Net interest deductions (Notes 6 and 7)	(63,700)	(68,020)	(69,602)
Other income (deductions)	12,300	4,411	(5,412)
Total other income and (expenses)	(51,400)	(63,609)	(75,014)
Income before income taxes	222,815	207,915	175,066
Income tax expense (Note 11)	77,942	75,276	63,303
Net income	144,873	132,639	111,763
Net income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Net income attributable to Southwest Gas Corporation	$ 145,320	$ 133,331	$ 112,287
Basic earnings per share (Note 14)	$ 3.14	$ 2.89	$ 2.45
Diluted earnings per share (Note 14)	$ 3.11	$ 2.86	$ 2.43
Average number of common shares outstanding	46,318	46,115	45,858
Average shares outstanding (assuming dilution)	46,758	46,555	46,291

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Thousands of dollars)

Year Ended December 31,	2013	2012	2011
Net Income	$144,873	$132,639	$111,763
Other comprehensive income (loss), net of tax			
Defined benefit pension plans (Notes 5 and 9):			
Net actuarial gain (loss)	62,214	(46,409)	(84,005)
Amortization of prior service cost	220	—	—
Amortization of transition obligation	—	538	537
Amortization of net actuarial loss	21,190	15,870	9,653
Prior service cost	—	(1,502)	—
Regulatory adjustment	(76,651)	26,518	65,677
Net defined benefit pension plans	6,973	(4,985)	(8,138)
Forward-starting interest rate swaps:			
Unrealized/realized gain (loss) (Notes 5 and 12)	—	1,834	(11,134)
Amounts reclassified into net income (Notes 5 and 12)	2,074	1,737	725
Net forward-starting interest rate swaps	2,074	3,571	(10,409)
Total other comprehensive income (loss), net of tax	9,047	(1,414)	(18,547)
Comprehensive income	153,920	131,225	93,216
Comprehensive income (loss) attributable to noncontrolling interest	(447)	(692)	(524)
Comprehensive income attributable to Southwest Gas Corporation	$154,367	$131,917	$ 93,740

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of dollars)

Year Ended December 31,	2013	2012	2011
CASH FLOW FROM OPERATING ACTIVITIES:			
Net Income	$ 144,873	$132,639	$111,763
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	236,817	223,422	200,469
Deferred income taxes	68,639	66,280	56,467
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	(22,556)	12,333	(61,641)
Accrued utility revenue	(700)	(1,700)	(5,900)
Deferred purchased gas costs	(111,143)	22,823	(52,885)
Accounts payable	27,668	(25,998)	15,826
Accrued taxes	925	113	14,979
Other current assets and liabilities	5,084	(18,948)	(3,347)
Gains on sale	(4,112)	(8,040)	(3,307)
Changes in undistributed stock compensation	6,958	5,137	6,125
AFUDC and property-related changes	(2,274)	(1,943)	(1,154)
Changes in other assets and deferred charges	(21,719)	(15,367)	11,025
Changes in other liabilities and deferred credits	17,749	(4,427)	(36,378)
Net cash provided by operating activities	$ 346,209	$386,324	$252,042

CONSOLIDATED STATEMENTS OF CASH FLOWS – Continued

Year Ended December 31,	2013	2012	2011
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(364,276)	(395,712)	(380,991)
Restricted cash	—	12,785	24,996
Changes in customer advances	7,773	(3,025)	(7,771)
Miscellaneous inflows	8,465	13,963	7,686
Miscellaneous outflows	—	(2,004)	(2,719)
Net cash used in investing activities	(348,038)	(373,993)	(358,799)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	1,635	1,581	7,402
Dividends paid	(59,535)	(53,040)	(47,929)
Interest rate swap settlement	—	(21,754)	—
Issuance of long-term debt, net	311,290	489,518	274,598
Retirement of long-term debt	(137,013)	(427,043)	(330,473)
Change in credit facility and commercial paper	(101,000)	2,000	109,000
Other	1,999	—	—
Net cash provided by (used in) financing activities	17,376	(8,738)	12,598
Change in cash and cash equivalents	15,547	3,593	(94,159)
Cash and cash equivalents at beginning of period	25,530	21,937	116,096
Cash and cash equivalents at end of period	$ 41,077	$ 25,530	$ 21,937
Supplemental information:			
Interest paid, net of amounts capitalized	$ 58,730	$ 87,439	$ 69,842
Income taxes paid (received)	$ 6,850	$ 2,843	$ (13,635)

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands, except per share amounts)

	Southwest Gas Corporation Equity						
	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
	Shares	Amount					
DECEMBER 31, 2010	45,599	$47,229	$807,885	$(30,784)	$343,131	$(465)	$1,166,996
Common stock issuances	357	357	13,755				14,112
Net income (loss)					112,287	(524)	111,763
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				(8,138)			(8,138)
FSIRS realized and unrealized loss, net of tax (Notes 5 and 12)				(11,134)			(11,134)
Amounts reclassified to net income, net of tax (Notes 5 and 12)				725			725
Dividends declared Common: $1.06 per share					(49,293)		(49,293)
DECEMBER 31, 2011	45,956	$47,586	$821,640	$(49,331)	$406,125	$(989)	$1,225,031
Common stock issuances	192	192	7,137				7,329
Net income (loss)					133,331	(692)	132,639
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				(4,985)			(4,985)
FSIRS realized and unrealized gain, net of tax (Notes 5 and 12)				1,834			1,834
Amounts reclassified to net income, net of tax (Notes 5 and 12)				1,737			1,737
Dividends declared Common: $1.18 per share					(55,087)		(55,087)

CONSOLIDATED STATEMENTS OF EQUITY – Continued

	Southwest Gas Corporation Equity						
	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest	Total
	Shares	Amount					
DECEMBER 31, 2012	46,148	$47,778	$828,777	$(50,745)	$484,369	$(1,681)	$1,308,498
Common stock issuances	208	208	11,744				11,952
Net income (loss)					145,320	(447)	144,873
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 9)				6,973			6,973
Amounts reclassified to net income, net of tax (Notes 5 and 12)				2,074			2,074
Dividends declared Common: $1.32 per share					(61,975)		(61,975)
DECEMBER 31, 2013	46,356*	$47,986	$840,521	$(41,698)	$567,714	$(2,128)	$1,412,395

* At December 31, 2013, 2.1 million common shares were registered and available for issuance under provisions of the Company's various stock issuance plans. In addition, approximately 52,000 common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 10).

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1 – Summary of Significant Accounting Policies

Nature of Operations. Southwest Gas Corporation and its subsidiaries (the "Company") consist of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Public utility rates, practices, facilities, and service territories of Southwest are subject to regulatory oversight. The timing and amount of rate relief can materially impact results of operations. Natural gas purchases and the timing of related recoveries can materially impact liquidity. NPL Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that primarily provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems. NPL also holds a 65% interest in a venture to market natural gas engine-driven heating, ventilating, and air conditioning ("HVAC") technology and products. NPL consolidates the entity (IntelliChoice Energy, LLC) as a majority-owned subsidiary.

Basis of Presentation. The Company follows generally accepted accounting principles in the United States ("U.S. GAAP") in accounting for all of its businesses. Accounting for the natural gas utility operations conforms with U.S. GAAP as applied to regulated companies and as prescribed by federal agencies and commissions of the various states in which the utility operates. The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Consolidation. The accompanying financial statements are presented on a consolidated basis and include the accounts of Southwest Gas Corporation and all subsidiaries. All significant intercompany balances and transactions have been eliminated with the exception of transactions between Southwest and NPL in accordance with accounting treatment for rate-regulated entities.

Net Utility Plant. Net utility plant includes gas plant at original cost, less the accumulated provision for depreciation and amortization, plus the unamortized balance of acquisition adjustments. Original cost includes contracted services, material, payroll and related costs such as taxes and benefits, general and administrative expenses, and an allowance for funds used during construction, less contributions in aid of construction.

Other Property and Investments. Other property and investments includes (millions of dollars):

	2013	2012
NPL property and equipment	$ 320	$ 287
NPL accumulated provision for depreciation and amortization	(163)	(136)
Net cash surrender value of COLI policies	93	80
Other property	11	11
Total	$ 261	$ 242

Deferred Purchased Gas Costs. The various regulatory commissions have established procedures to enable Southwest to adjust its billing rates for changes in the cost of natural gas purchased. The difference between the current cost of gas purchased and the cost of gas recovered in billed rates is deferred. Generally, these deferred amounts are recovered or refunded within one year.

Prepaids and other current assets. Prepaids and other current assets includes gas pipe inventory and operating supplies of $21 million in 2013 and $25 million in 2012.

Income Taxes. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date. For regulatory and financial reporting purposes, investment tax credits ("ITC") related to gas utility operations are deferred and amortized over the life of related fixed assets.

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a purchase-date maturity of three months or less. Cash and cash equivalents fall within Level 1 (quoted prices for identical financial instruments) of the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability. During 2012 and 2013, approximately $20 million and $9.3 million, respectively, of customer advances, upon contract expiration, were applied as contributions toward utility construction activity and represent a non-cash investing activity.

Accumulated Removal Costs. Approved regulatory practices allow Southwest to include in depreciation expense a component to recover removal costs associated with utility plant retirements. In accordance with the Securities and Exchange Commission's ("SEC") position on presentation of these amounts, management has reclassified estimated removal costs from accumulated depreciation to accumulated removal costs within the liabilities section of the balance sheets. The reclassified amounts are presented in the table below (thousands of dollars):

	December 31, 2013	December 31, 2012
Accumulated removal costs	$279,000	$256,000

Gas Operating Revenues. Revenues are recorded when customers are billed. Customer billings are based on monthly meter reads and are calculated in accordance with applicable tariffs and state and local laws, regulations, and agreements. An estimate of the margin associated with natural gas service provided, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period is also recognized as accrued utility revenue. Revenues also include the net impacts of margin tracker/decoupling accruals.

The Company acts as an agent for state and local taxing authorities in the collection and remission of a variety of taxes, including sales and use taxes and surcharges. These taxes are not included in gas operating revenues. The Company uses the net classification method to report taxes collected from customers to be remitted to governmental authorities.

Construction Revenues. The majority of NPL contracts are performed under unit-price contracts. Generally, these contracts state prices per unit of installation. Typical installations are accomplished in two weeks or less. Revenues are recorded as installations are completed. Long-term fixed-price contracts use the percentage-of-completion method of accounting and, therefore, take into account the cost, estimated earnings, and revenue to date on contracts not yet completed. The amount of revenue recognized on fixed-price contracts is based on costs expended to date relative to anticipated final contract costs. Revisions in estimates of costs and earnings during the course of work are reflected in the accounting period in which the facts requiring revision become known. If a loss on a contract becomes known or is anticipated, the entire amount of the estimated ultimate loss is recognized at that time in the financial statements. Some unit-price contracts contain caps, that if encroached, trigger revenue and loss recognition similar to a fixed-price contract model.

In 2011, NPL recorded $5 million in estimated pretax profit associated with a large fixed-price contract. In connection with significant changes in estimated costs to complete the fixed-price contract, NPL results for 2012 reflected a pretax loss of $15 million ($0.20 per share, after tax). The estimated cost changes that resulted in the loss recognized included reductions in projected productivity and higher costs of restoration work. During 2013, profitability on this contract was minimal and as of December 31, 2013, this fixed-price contract is substantially complete.

Construction Expenses. The construction expenses classification in the income statement includes payroll expenses, job-related equipment costs, direct construction costs, gains and losses on equipment sales, general and administrative expenses, and office-related fixed costs of NPL.

Net Cost of Gas Sold. Components of net cost of gas sold include natural gas commodity costs (fixed-price and variable-rate), pipeline capacity/transportation costs, and actual settled costs of natural gas derivative instruments. Also included are the net impacts of PGA deferrals and recoveries.

Operations and Maintenance Expense. For financial reporting purposes, operations and maintenance expense includes Southwest's operating and maintenance costs associated with serving utility customers, uncollectible expense, administrative and general salaries and expense, employee benefits expense, and legal expense (including injuries and damages).

Depreciation and Amortization. Utility plant depreciation is computed on the straight-line remaining life method at composite rates considered sufficient to amortize costs over estimated service lives, including components which compensate for removal costs (net of salvage value), and retirements, as approved by the appropriate regulatory agency. When plant is retired from service, the original cost of plant, including cost of removal, less salvage, is charged to the accumulated provision for depreciation. Other regulatory assets, including acquisition adjustments, are amortized when appropriate, over time periods authorized by regulators. Nonutility and construction services-related property and equipment are depreciated on a straight-line method based on the estimated useful lives of the related assets. Costs and gains related to refunding utility debt and debt issuance expenses are deferred and amortized over the weighted-average lives of the new issues and become a component of interest expense.

Allowance for Funds Used During Construction ("AFUDC"). AFUDC represents the cost of both debt and equity funds used to finance utility construction. AFUDC is capitalized as part of the cost of utility plant. The debt portion of AFUDC is reported in the consolidated statements of income as an offset to net interest deductions and the equity portion is reported as other income. Utility plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into operation, and general rate relief is requested and granted.

	2013	2012	2011
(In thousands)			
AFUDC:			
Debt portion	$1,260	$1,129	$ 718
Equity portion	2,274	1,943	1,154
AFUDC capitalized as part of utility plant	$3,534	$3,072	$1,872

Other Income (Deductions). The following table provides the composition of significant items included in Other Income (deductions) on the consolidated statements of income (thousands of dollars):

	2013	2012	2011
Change in COLI policies	$12,400	$ 6,600	$ 700
Interest income	461	924	485
Pipe replacement costs	(132)	(2,680)	(4,761)
Miscellaneous income and (expense)	(429)	(433)	(1,836)
Total other income (deductions)	$12,300	$ 4,411	$(5,412)

Included in the table above is the change in cash surrender values of company-owned life insurance ("COLI") policies (including net death benefits recognized). Changes in cash surrender values are directly influenced by the investment portfolio underlying the insurance policies. These life insurance policies on members of management and other key employees are used by Southwest to indemnify itself against the loss of talent, expertise, and knowledge, as well as to provide indirect funding for certain nonqualified benefit plans. Current tax regulations provide for tax-free treatment of life insurance (death benefit) proceeds. Therefore, changes in the cash surrender value components of COLI policies, as they progress towards the ultimate death benefits, are also recorded without tax consequences. Pipe replacement costs include amounts associated with certain Arizona non-recoverable pipe replacement work. The replacement program work subject to non-recoverability was substantially completed in 2012.

Earnings Per Share. Basic earnings per share ("EPS") are calculated by dividing net income by the weighted-average number of shares outstanding during the period. Diluted EPS includes the effect of additional weighted-average common stock equivalents (stock options, performance shares, and restricted stock units). Unless otherwise noted, the term "Earnings Per Share" refers to Basic EPS. A reconciliation of the shares used in the Basic and Diluted EPS calculations is shown in the following table. Net income was the same for Basic and Diluted EPS calculations.

	2013	2012	2011
(In thousands)			
Average basic shares	46,318	46,115	45,858
Effect of dilutive securities:			
Stock options	26	42	52
Performance shares	231	254	271
Restricted stock units	183	144	110
Average diluted shares	46,758	46,555	46,291

Subsequent Events. Management of the Company monitors events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued or disclosures to be made, and has reflected them where appropriate.

Note 2 – Utility Plant

Net utility plant as of December 31, 2013 and 2012 was as follows (thousands of dollars):

December 31,	2013	2012
Gas plant:		
Storage	$ 21,282	$ 20,503
Transmission	313,306	301,505
Distribution	4,410,598	4,224,560
General	324,490	310,936
Other	182,793	161,996
	5,252,469	5,019,500
Less: accumulated depreciation	(1,868,504)	(1,750,795)
Acquisition adjustments, net	730	911
Construction work in progress	101,413	74,178
Net utility plant	$ 3,486,108	$ 3,343,794

Depreciation and amortization expense on gas plant was as follows (thousands of dollars):

	2013	2012	2011
Depreciation and amortization expense	$185,283	$182,612	$172,712

Operating Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas. A lease on the administrative offices in Phoenix recently expired. A new facility was acquired to replace the previously leased facility. The Company owns the new facility which is included in net utility plant above. The table below presents the rental payments and the current term expiration dates. The corporate headquarters lease has optional renewal terms available and the Company will consider alternatives at that time.

	2014	2015	2016	2017	2018
(In thousands)					
Corporate headquarters (expires in 2017)	$2,190	$2,270	$2,343	$1,194	$—
Phoenix administrative offices (expired in 2014)	243	—	—	—	—

In addition to the above, the Company leases certain office and construction equipment. The majority of these leases are short-term. These leases are accounted for as operating leases and, for the gas segment, are also treated as such for regulatory purposes. NPL has various short-term operating leases of equipment and temporary office sites. The table below presents Southwest rental payments and NPL lease payments that are included in operating expenses (in thousands):

	2013	2012	2011
Southwest Gas	$ 8,308	$ 7,762	$ 7,812
NPL	27,118	24,054	19,017
Consolidated rental payments/lease expense	$35,426	$31,816	$26,829

The following is a schedule of future minimum lease payments for significant non-cancelable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2013 (thousands of dollars):

Year Ending December 31,	
2014	$ 6,780
2015	5,231
2016	4,370
2017	2,716
2018	928
Thereafter	1,206
Total minimum lease payments	$21,231

Note 3 – Receivables and Related Allowances

Business activity with respect to gas utility operations is conducted with customers located within the three-state region of Arizona, Nevada, and California. The table below contains information about the gas utility customer accounts receivable balance (net of allowance) at December 31, 2013, and the percentage of customers in each of the three states.

Gas utility customer accounts receivable balance (in thousands)	$121,082

	December 31, 2013
Percent of customers by state	
Arizona	54%
Nevada	36%
California	10%

Although the Company seeks to minimize its credit risk related to utility operations by requiring security deposits from new customers, imposing late fees, and actively pursuing collection on overdue accounts, some accounts are ultimately not collected. Customer accounts are subject to collection procedures that vary by jurisdiction (late fee assessment, noticing requirements for disconnection of service, and procedures for actual disconnection and/or reestablishment of service). After disconnection of service, accounts are generally written off approximately one month after inactivation. Dependent upon the jurisdiction, reestablishment of service requires both payment of previously unpaid balances and additional deposit requirements. Provisions for uncollectible accounts are recorded monthly based on experience, customer and rate composition, and write-off processes. They are included in the ratemaking process as a cost of service. The Nevada jurisdictions have a regulatory mechanism associated with the gas cost-related portion of uncollectible accounts. Such amounts are deferred and collected through a surcharge in the ratemaking process. Activity in the allowance account for uncollectibles is summarized as follows (thousands of dollars):

	Allowance for Uncollectibles
Balance, December 31, 2010	$ 3,194
Additions charged to expense	2,678
Accounts written off, less recoveries	(2,690)
Balance, December 31, 2011	3,182
Additions charged to expense	2,471
Accounts written off, less recoveries	(3,149)
Balance, December 31, 2012	2,504
Additions charged to expense	3,583
Accounts written off, less recoveries	(4,362)
Balance, December 31, 2013	$ 1,725

At December 31, 2013, the construction services segment (NPL) had $93 million in customer accounts receivable. Both the allowance for uncollectibles and write-offs have been insignificant and are not reflected in the table above.

Note 4 – Regulatory Assets and Liabilities

Natural gas operations are subject to the regulation of the Arizona Corporation Commission ("ACC"), the Public Utilities Commission of Nevada ("PUCN"), the California Public Utilities Commission ("CPUC"), and the Federal Energy Regulatory Commission ("FERC"). Accounting policies of Southwest conform to U.S. GAAP applicable to rate-regulated entities and reflect the effects of the ratemaking process. Accounting treatment for rate-regulated entities allows for deferral as regulatory assets, costs that otherwise would be expensed, if it is probable that future recovery from customers will occur. If rate recovery is no longer probable, due to competition or the actions of regulators, Southwest is required to write-off the related regulatory asset. Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process.

The following table represents existing regulatory assets and liabilities (thousands of dollars):

December 31,	2013	2012
Regulatory assets:		
Accrued pension and other postretirement benefit costs (1)	$ 249,985	$ 373,615
Unrealized net loss on non-trading derivatives (Swaps) (2)	160	2,395
Deferred purchased gas costs (3)	18,217	6,031
Accrued purchased gas costs (4)	31,500	30,300
Unamortized premium on reacquired debt (5)	19,614	19,452
Other (6)	48,945	44,927
	368,421	476,720
Regulatory liabilities:		
Deferred purchased gas costs (3)	—	(98,957)
Accumulated removal costs	(279,000)	(256,000)
Unrealized net gain on non-trading derivatives (Swaps) (2)	(981)	(6)
Deferred gain on southern Nevada division operations facility (7)	(253)	(392)
Unamortized gain on reacquired debt (8)	(11,398)	(11,934)
Other (9)	(26,482)	(6,951)
Net regulatory assets	$ 50,307	$ 102,480

(1) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovery period is greater than five years. (See Note 9).

(2) The following table details the regulatory assets/(liabilities) offsetting the derivatives (Swaps) at fair value in the balance sheets (thousands of dollars). The actual amounts, when realized at settlement, become a component of purchased gas costs under the Company's purchased gas adjustment ("PGA") mechanisms. (See Note 12).

Instrument	Balance Sheet Location	2013	2012
Swaps	Deferred charges and other assets	$ 4	$ 319
Swaps	Prepaids and other current assets	156	2,076
Swaps	Other current liabilities	(801)	—
Swaps	Other deferred credits	(180)	(6)

(3) Balance recovered or refunded on an ongoing basis with interest.

(4) Included in Prepaids and other current assets on the Consolidated Balance Sheets. Balance recovered or refunded on an ongoing basis.

(5) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovered over life of debt instruments.

(6) Other regulatory assets including deferred costs associated with rate cases, regulatory studies, and state mandated public purpose programs (including low income and conservation programs), as well as margin and interest-tracking accounts, amounts associated with accrued absence time, and deferred post-retirement benefits other than pensions. Recovery periods vary.

(7) Balance was originally being amortized over a four-year period beginning in the fourth quarter of 2009. As a result of the most recent Nevada general rate case, the amortization period was extended through 2015.

(8) Included in Other deferred credits on the Consolidated Balance Sheet. Amortized over life of debt instruments.

(9) Other regulatory liabilities includes amounts associated with income tax and gross-up.

Note 5 – Other Comprehensive Income and Accumulated Other Comprehensive Income ("AOCI")

The following information provides insight into amounts impacting Other Comprehensive Income (Loss), both before and after-tax, within the Consolidated Statements of Comprehensive Income, which also impact Accumulated Other Comprehensive Income in the Company's Consolidated Balance Sheets and Consolidated Statements of Equity.

Related Tax Effects Allocated to Each Component of Other Comprehensive Income (Loss)

	2013			2012			2011		
	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount	Before-Tax Amount	Tax (Expense) or Benefit (1)	Net-of-Tax Amount
(Thousands of dollars)									
Defined benefit pension plans:									
Net actuarial gain/(loss)	$ 100,345	$(38,131)	$ 62,214	$(74,853)	$ 28,444	$(46,409)	$(135,492)	$ 51,487	$(84,005)
Amortization of prior service cost	355	(135)	220	—	—	—	—	—	—
Amortization of transition obligation	—	—	—	867	(329)	538	867	(330)	537
Amortization of net actuarial (gain)/loss	34,177	(12,987)	21,190	25,597	(9,727)	15,870	15,569	(5,916)	9,653
Prior service cost	—	—	—	(2,423)	921	(1,502)	—	—	—
Regulatory adjustment	(123,630)	46,979	(76,651)	42,771	(16,253)	26,518	105,931	(40,254)	65,677
Pension plans other comprehensive income (loss)	11,247	(4,274)	6,973	(8,041)	3,056	(4,985)	(13,125)	4,987	(8,138)
FSIRS (designated hedging activities):									
Unrealized/realized gain (loss)	—	—	—	2,959	(1,125)	1,834	(17,958)	6,824	(11,134)
Amounts reclassified into net income	3,345	(1,271)	2,074	2,801	(1,064)	1,737	1,169	(444)	725
FSIRS other comprehensive income (loss)	3,345	(1,271)	2,074	5,760	(2,189)	3,571	(16,789)	6,380	(10,409)
Total other comprehensive income (loss)	$ 14,592	$ (5,545)	$ 9,047	$ (2,281)	$ 867	$ (1,414)	$ (29,914)	$ 11,367	$(18,547)

(1) Tax amounts are calculated using a 38% rate.

The estimated amounts that will be amortized from accumulated other comprehensive income or regulatory assets into net periodic benefit cost over the next year are summarized below (in thousands):

Retirement plan net actuarial loss	$23,000
SERP net actuarial loss	800
PBOP prior service cost	400

Approximately $2.1 million of previously realized losses (net of tax) related to the forward-starting interest rate swaps ("FSIRS"), included in AOCI at December 31, 2013, will be reclassified into interest expense within the next twelve months as the related interest payments on long-term debt occur.

The following table represents a rollforward of AOCI, presented on the Company's Consolidated Balance Sheets and its Consolidated Statements of Equity:

AOCI – Rollforward
(Thousands of dollars)

	Defined Benefit Plans (Note 9)			FSIRS (Note 12)			
	Before-Tax	Tax (Expense) Benefit	After-Tax	Before-Tax	Tax (Expense) Benefit	After-Tax	AOCI
Beginning Balance AOCI December 31, 2012	$ (52,470)	$ 19,939	$(32,531)	$(29,378)	$11,164	$(18,214)	$(50,745)
Net actuarial gain/(loss)	100,345	(38,131)	62,214	—	—	—	62,214
Other comprehensive income before reclassifications	100,345	(38,131)	62,214	—	—	—	62,214
FSIRS amounts reclassified from AOCI (1)	—	—	—	3,345	(1,271)	2,074	2,074
Amortization of prior service cost (2)	355	(135)	220	—	—	—	220
Amortization of net actuarial loss (2)	34,177	(12,987)	21,190	—	—	—	21,190
Regulatory adjustment (3)	(123,630)	46,979	(76,651)	—	—	—	(76,651)
Net current period other comprehensive income (loss)	11,247	(4,274)	6,973	3,345	(1,271)	2,074	9,047
Ending Balance AOCI December 31, 2013	$ (41,223)	$ 15,665	$(25,558)	$(26,033)	$ 9,893	$(16,140)	$(41,698)

(1) The FSIRS reclassification amounts are included in the Net interest deductions line item on the Consolidated Statements of Income.

(2) These AOCI components are included in the computation of net periodic benefit cost (see Note 9 – Pension and Other Postretirement Benefits for additional details).

(3) The regulatory adjustment represents the portion of the activity above that is expected to be recovered through rates in the future (the related regulatory asset is included in the Deferred charges and other assets line item on the Consolidated Balance Sheets).

The following table represents amounts (before income tax impacts) included in Accumulated other comprehensive income (in the table above), that have not yet been recognized in net periodic benefit cost, as of December 31, 2013 and 2012:

Amounts Recognized in AOCI (Before Tax)
(Thousands of dollars)

	2013	2012
Net actuarial (loss) gain	$(289,141)	$(423,662)
Prior service cost	(2,067)	(2,423)
Less: amount recognized in regulatory assets	249,985	373,615
Recognized in AOCI	$ (41,223)	$ (52,470)

See **Note 9 – Pension and Other Postretirement Benefits** for more information on the defined benefit pension plans and **Note 12 – Derivatives and Fair Value Measurements** for more information on the FSIRS.

Note 6 – Long-Term Debt

Carrying amounts of the Company's long-term debt and their related estimated fair values as of December 31, 2013 and December 31, 2012 are disclosed in the following table. The fair values of the revolving credit facility (including commercial paper), the NPL revolving credit facility, and the variable-rate Industrial Development Revenue Bonds ("IDRBs") approximate their carrying values, and are categorized as Level 1 (quoted prices for identical financial instruments) within the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability. The market values of debentures (except the 6.1% Notes) and fixed-rate IDRBs are categorized as Level 2. The 6.1% Notes (private placement) and NPL other debt obligations (not actively traded) are categorized as Level 3 (based on significant unobservable inputs to their fair values). Fair values for the debentures, fixed-rate IDRBs, and NPL other debt obligations were determined through a market-based valuation approach, where fair market values are determined based on evaluated pricing data, such as broker quotes and yields for similar securities adjusted for observable differences. Significant inputs used in the valuation generally include benchmark yield curves and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

December 31,	2013		2012	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
Notes, 4.45%, due 2020	$125,000	$130,953	$125,000	$141,771
Notes, 6.1%, due 2041	125,000	141,873	125,000	165,779
Notes, 3.875%, due 2022	250,000	252,485	250,000	277,950
Notes, 4.875%, due 2043	250,000	257,280	—	—
8% Series, due 2026	75,000	96,263	75,000	111,501
Medium-term notes, 7.59% series, due 2017	25,000	28,741	25,000	30,710
Medium-term notes, 7.78% series, due 2022	25,000	30,586	25,000	34,637
Medium-term notes, 7.92% series, due 2027	25,000	31,497	25,000	36,953
Medium-term notes, 6.76% series, due 2027	7,500	8,468	7,500	10,058
Unamortized discount	(5,560)		(3,403)	
	901,940		654,097	
Revolving credit facility and commercial paper	10,000	10,000	111,000	111,000

December 31,	2013		2012	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Industrial development revenue bonds:				
Variable-rate bonds:				
Tax-exempt Series A, due 2028	50,000	50,000	50,000	50,000
2003 Series A, due 2038	50,000	50,000	50,000	50,000
2008 Series A, due 2038	50,000	50,000	50,000	50,000
2009 Series A, due 2039	50,000	50,000	50,000	50,000
Fixed-rate bonds:				
5.55% 1999 Series D, due 2038	—	—	8,270	8,375
5.45% 2003 Series C, due 2038	—	—	30,000	30,152
5.25% 2003 Series D, due 2038	20,000	20,150	20,000	20,571
5.80% 2003 Series E, due 2038	—	—	15,000	15,102
5.25% 2004 Series A, due 2034	65,000	64,522	65,000	66,955
5.00% 2004 Series B, due 2033	31,200	30,284	31,200	31,655
4.85% 2005 Series A, due 2035	100,000	95,192	100,000	101,184
4.75% 2006 Series A, due 2036	24,855	22,974	24,855	25,189
Unamortized discount	(2,776)		(3,195)	
	438,279		491,130	
NPL credit facility	—	—	41,562	41,562
NPL other debt obligations	42,213	42,119	20,721	20,991
	1,392,432		1,318,510	
Less: current maturities	(11,105)		(50,137)	
Long-term debt, less current maturities	$1,381,327		$1,268,373	

In March 2013, the Company redeemed at par the 5.45% Series 2003C and the 5.80% Series 2003E IDRBs originally due in 2038. The Company facilitated the redemption primarily from borrowings under its $300 million credit facility. In September 2013, the Company redeemed at par the $8.27 million 5.55% 1999 Series D IDRBs originally due in 2038. The Company facilitated the redemption primarily from borrowings under its $300 million credit facility.

In October 2013, the Company issued $250 million of 4.875% senior notes at a 0.078% discount. The notes will mature in October 2043. A portion of the net proceeds were used to temporarily pay down amounts outstanding under the credit facility. The remaining net proceeds were used for general corporate purposes.

The Company has a $300 million revolving credit facility that expires in March 2017. Interest rates for the credit facility are calculated at either the London Interbank Offered Rate ("LIBOR") or an "alternate base rate," plus in each case an applicable margin that is determined based on the Company's senior unsecured debt rating. At December 31, 2013, the applicable margin is 1% for loans bearing interest with reference to LIBOR and 0% for loans bearing interest with reference to the alternative base rate. Southwest has designated $150 million of the $300 million facility for long-term borrowing needs and the remaining $150 million for working capital purposes. At December 31, 2013, no borrowings were outstanding on the credit facility (see commercial paper program discussion below). Borrowings under the credit facility ranged from none during the fourth quarter of 2013 to a high of $195 million during October 2013. There were no borrowings outstanding on the short-term portion of the credit facility at December 31, 2012 and 2013. (See **Note 7 – Short-Term Debt**).

The Company has a $50 million commercial paper program. Any issuance under the commercial paper program is supported by the Company's current revolving credit facility and, therefore, does not represent additional borrowing capacity. Any borrowing under the commercial paper program will be designated as long-term debt. Interest rates for the program are calculated at the then current commercial paper rate. At December 31, 2013, $10 million was outstanding on the commercial paper program. The effective interest rate on the commercial paper program was 0.54% at December 31, 2013.

NPL has a $75 million credit facility that is scheduled to expire in June 2015. Interest rates for the credit facility are calculated at either LIBOR or a base rate, plus, in each case, 1.00% or 0.75% depending on NPL's leverage ratio at the end of each quarter. At December 31, 2013, no borrowings were outstanding on the NPL credit facility.

The effective interest rates on the variable-rate IDRBs are included in the table below:

	December 31, 2013	December 31, 2012
2003 Series A	1.43%	1.71%
2008 Series A	1.41%	1.59%
2009 Series A	1.01%	1.14%
Tax-exempt Series A	1.07%	1.25%

In Nevada, interest fluctuations due to changing interest rates on the 2003 Series A, 2008 Series A, and 2009 Series A variable-rate IDRBs are tracked and recovered from ratepayers through an interest balancing account.

Estimated maturities of long-term debt for the next five years are (in thousands):

2014	$11,105
2015	11,100
2016	10,200
2017	42,210
2018	2,598

No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain securities ratings covenants that, if set in motion, would increase financing costs. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2013, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.9 billion in additional debt and meet the leverage ratio requirement. The Company has at least $800 million of cushion in equity relating to the minimum net worth requirement.

Note 7 – Short-Term Debt

As discussed in Note 6, Southwest has a $300 million credit facility that is scheduled to expire in March 2017, of which $150 million has been designated by management for working capital purposes. The Company had no short-term borrowings outstanding at December 31, 2012 or 2013.

Note 8 – Commitments and Contingencies

The Company is a defendant in miscellaneous legal proceedings. The Company is also a party to various regulatory proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that no litigation or regulatory proceeding to which the Company is currently subject will have a material adverse impact on its financial position or results of operations.

The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In connection with these liability insurance policies, the Company is responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers are responsible for amounts up to the policy limits. The self-insured retention amount associated with general liability claims is $1 million per incident plus payment of the first $4 million in aggregate claims above $1 million in the policy year.

Note 9 – Pension and Other Postretirement Benefits

Southwest has an Employees' Investment Plan that provides for purchases of various mutual fund investments and Company common stock by eligible Southwest employees through deduction of a percentage of base compensation, subject to IRS limitations. Southwest matches up to one-half of amounts deferred. The maximum matching contribution is 3.5% of an employee's annual compensation. NPL has a separate plan, the cost and liability of which are not significant. The cost of the Southwest plan is listed below (in thousands):

	2013	2012	2011
Employee Investment Plan cost	$4,850	$4,707	$4,626

Southwest has a deferred compensation plan for all officers and a separate deferred compensation plan for members of the Board of Directors. The plans provide the opportunity to defer up to 100% of annual cash compensation. Southwest matches one-half of amounts deferred by officers, up to a maximum matching contribution of 3.5% of an officer's annual base salary. Upon retirement, payments of compensation deferred, plus interest, are made in equal monthly installments over 10, 15, or 20 years, as elected by the participant. Directors have an additional option to receive such payments over a five-year period. Deferred compensation earns interest at a rate determined each January. The interest rate equals 150% of Moody's Seasoned Corporate Bond Rate Index.

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees and a separate unfunded supplemental retirement plan ("SERP") which is limited to officers. Southwest also provides postretirement benefits other than pensions ("PBOP") to its qualified retirees for health care, dental, and life insurance benefits.

The Company recognizes the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in its balance sheets. Any actuarial gains and losses, prior service costs and transition assets or obligations are recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost.

In accordance with regulatory deferral accounting treatment under U.S. GAAP for rate-regulated entities, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. Changes in actuarial gains and losses and prior service costs pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are amortized and recognized as components of net periodic pension costs each year.

Investment objectives and strategies for the qualified retirement plan are developed and approved by the Pension Plan Investment Committee of the Board of Directors of the Company. They are designed to enhance capital, maintain minimum liquidity required for retirement plan operations and effectively manage pension assets.

A target portfolio of investments in the qualified retirement plan is developed by the Pension Plan Investment Committee and is reevaluated periodically. Asset return assumptions are determined by evaluating performance expectations of the target portfolio. Projected benefit obligations are estimated using actuarial assumptions and Company benefit policy. A target mix of assets is then determined based on acceptable risk versus estimated returns in order to fund the benefit obligation. At December 31, 2013, the percentage ranges of the target portfolio are:

Type of Investment	Percentage Range
Equity securities	59 to 71
Debt securities	31 to 37
Other	up to 5

The Company's pension costs for these plans are affected by the amount and timing of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions, particularly the discount rate, may significantly affect pension costs and plan obligations for the qualified retirement plan.

U.S. GAAP states that the assumed discount rate should reflect the rate at which the pension benefits could be effectively settled. In making this estimate, in addition to rates implicit in current prices of annuity contracts that could be used to settle the liabilities, employers may look to rates of return on high-quality fixed-income investments available on December 31 of each year and expected to be available during the period to maturity of the pension benefits. In determining the discount rate, the Company matches the plan's projected cash flows to a spot-rate yield curve based on highly rated corporate bonds. Changes to the discount rate from year-to-year, if any, are generally made in increments of 25 basis points.

Due to a higher interest rate environment for high-quality fixed income investments, the Company raised the discount rate at December 31, 2013 from 2012. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase was also raised (consistent with management's expectations overall). The asset return assumption (which impacts the following year's expense) was reduced. The rates are presented in the table below:

	December 31, 2013	December 31, 2012
Discount rate	5.00%	4.25%
Weighted-average rate of compensation increase	3.25%	2.75%
Asset return assumption	7.75%	8.00%

The significant increase in the discount rate will decrease the expense level for 2014. Pension expense for 2014 is estimated to decrease by $9 million. Future years expense level movements (up or down) will continue to be greatly influenced by long-term interest rates, asset returns, and funding levels.

The following table sets forth the retirement plan, SERP, and PBOP funded statuses and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

	2013			2012		
	Qualified Retirement Plan	SERP	PBOP	Qualified Retirement Plan	SERP	PBOP
(Thousands of dollars)						
Change in benefit obligations						
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 902,812	$ 37,373	$ 59,704	$ 780,571	$ 33,827	$ 52,182
Service cost	23,056	373	1,220	20,319	274	977
Interest cost	37,607	1,535	2,482	38,266	1,629	2,547
Plan amendments	—	—	—	—	—	2,423
Actuarial loss (gain)	(44,768)	(661)	(4,073)	92,409	4,111	2,775
Benefits paid	(31,993)	(2,477)	(1,313)	(28,753)	(2,468)	(1,200)
Benefit obligation at end of year (PBO/PBO/APBO)	886,714	36,143	58,020	902,812	37,373	59,704
Change in plan assets						
Market value of plan assets at beginning of year	609,750	—	35,250	521,829	—	29,944
Actual return on plan assets	96,187	—	7,319	68,174	—	4,454
Employer contributions	46,000	2,477	169	48,500	2,468	1,256
Benefits paid	(31,993)	(2,477)	(424)	(28,753)	(2,468)	(404)
Market value of plan assets at end of year	719,944	—	42,314	609,750	—	35,250
Funded status at year end	$(166,770)	$(36,143)	$(15,706)	$(293,062)	$(37,373)	$(24,454)
Weighted-average assumptions (benefit obligation)						
Discount rate	5.00%	5.00%	5.00%	4.25%	4.25%	4.25%
Weighted-average rate of compensation increase	3.25%	3.25%	3.25%	2.75%	2.75%	2.75%

Estimated funding for the plans above during calendar year 2014 is approximately $39 million of which $36 million pertains to the retirement plan. Management monitors plan assets and liabilities and could, at its discretion, increase plan funding levels above the minimum in order to achieve a desired funded status and avoid or minimize potential benefit restrictions.

The accumulated benefit obligation for the retirement plan and the SERP is presented below (in thousands):

	December 31, 2013	December 31, 2012
Retirement plan	$794,919	$811,184
SERP	33,894	35,362

Benefits expected to be paid for the pension, PBOP, and the SERP over the next 10 years are as follows (in millions):

	2014	2015	2016	2017	2018	2019-2023
Pension	$35.8	$37.4	$39.7	$41.7	$44.0	$257.3
PBOP	2.9	3.1	3.3	3.5	3.6	18.3
SERP	2.5	2.5	2.5	2.6	2.6	13.0

No assurance can be made that actual funding and benefits paid will match these estimates.

For PBOP measurement purposes, the per capita cost of the covered health care benefits medical rate trend assumption is 6.5% declining to 5%. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays all covered health care costs for employees who retired prior to 1989. The medical trend rate assumption noted above applies to the benefit obligations of pre-1989 retirees only.

Components of net periodic benefit cost

	Qualified Retirement Plan			SERP			PBOP		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
(Thousands of dollars)									
Service cost	$ 23,056	$ 20,319	$ 17,725	$ 373	$ 274	$ 217	$ 1,220	$ 977	$ 858
Interest cost	37,607	38,266	37,276	1,535	1,629	1,766	2,482	2,547	2,631
Expected return on plan assets	(49,840)	(45,780)	(40,114)	—	—	—	(2,824)	(2,404)	(2,379)
Amortization of prior service cost	—	—	—	—	—	—	355	—	—
Amortization of transition obligation	—	—	—	—	—	—	—	867	867
Amortization of net actuarial loss	32,261	23,883	14,348	971	683	631	945	1,031	590
Net periodic benefit cost	$ 43,084	$ 36,688	$ 29,235	$2,879	$2,586	$2,614	$ 2,178	$ 3,018	$ 2,567
Weighted-average assumptions (net benefit cost)									
Discount rate	4.25%	5.00%	5.75%	4.25%	5.00%	5.75%	4.25%	5.00%	5.75%
Expected return on plan assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Weighted-average rate of compensation increase	2.75%	3.00%	3.25%	2.75%	3.00%	3.25%	2.75%	3.00%	3.25%

Other Changes in Plan Assets and Benefit Obligations Recognized in Net Periodic Benefit Cost and Other Comprehensive Income

	2013				2012				2011			
	Total	Qualified Retirement Plan	SERP	PBOP	Total	Qualified Retirement Plan	SERP	PBOP	Total	Qualified Retirement Plan	SERP	PBOP
(Thousands of dollars)												
Net actuarial loss (gain) (a)	$(100,345)	$(91,115)	$ (662)	$(8,568)	$ 74,853	$ 70,016	$4,111	$ 726	$ 135,492	$ 127,651	$2,427	$ 5,414
Amortization of prior service cost (b)	(355)	—	—	(355)	—	—	—	—	—	—	—	—
Amortization of transition obligation (b)	—	—	—	—	(867)	—	—	(867)	(867)	—	—	(867)
Amortization of net actuarial loss (b)	(34,177)	(32,261)	(971)	(945)	(25,597)	(23,883)	(683)	(1,031)	(15,569)	(14,348)	(631)	(590)
Prior service cost	—	—	—	—	2,423	—	—	2,423	—	—	—	—
Regulatory adjustment	123,630	113,762	—	9,868	(42,771)	(41,520)	—	(1,251)	(105,931)	(101,974)	—	(3,957)
Recognized in other comprehensive (income) loss	(11,247)	(9,614)	(1,633)	—	8,041	4,613	3,428	—	13,125	11,329	1,796	—
Net periodic benefit costs recognized in net income	48,141	43,084	2,879	2,178	42,292	36,688	2,586	3,018	34,416	29,235	2,614	2,567
Total of amount recognized in net periodic benefit cost and other comprehensive (income) loss	$ 36,894	$ 33,470	$ 1,246	$ 2,178	$ 50,333	$ 41,301	$6,014	$ 3,018	$ 47,541	$ 40,564	$4,410	$ 2,567

The table above discloses the net gain or loss, prior service cost, and transition amount recognized in other comprehensive income, separated into (a) amounts initially recognized in other comprehensive income, and (b) amounts subsequently recognized as adjustments to other comprehensive income as those amounts are amortized as components of net periodic benefit cost.

See also **Note 5 – Other Comprehensive Income and Accumulated Other Comprehensive Income** ("AOCI").

U.S. GAAP states that a fair value measurement should be based on the assumptions that market participants would use in pricing the asset or liability and establishes a fair value hierarchy that ranks the inputs used to measure fair value by their reliability. The three levels of the fair value hierarchy are as follows:

Level 1 – quoted prices (unadjusted) in active markets for identical assets or liabilities that a company has the ability to access at the measurement date.

Level 2 – inputs other than quoted prices included within Level 1 that are observable for similar assets or liabilities, either directly or indirectly.

Level 3 – unobservable inputs for the asset or liability. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

The following table sets forth, by level within the three-level fair value hierarchy, the fair values of the assets of the qualified pension plan and the PBOP as of December 31, 2013 and December 31, 2012. The SERP has no assets. There were no transfers between Levels 1 and 2 during 2013.

	December 31, 2013			December 31, 2012		
	Qualified Retirement Plan	PBOP	Total	Qualified Retirement Plan	PBOP	Total
Assets at fair value (thousands of dollars):						
Level 1 – Quoted prices in active markets for identical financial assets						
Common stock						
Agriculture	$ 8,224	$ 244	$ 8,468	$ 8,878	$ 269	$ 9,147
Capital equipment	3,891	115	4,006	3,510	106	3,616
Chemicals/materials	8,228	244	8,472	6,741	204	6,945
Consumer goods	54,329	1,611	55,940	49,247	1,492	50,739
Energy and mining	36,126	1,071	37,197	39,454	1,195	40,649
Finance/insurance	37,643	1,116	38,759	28,861	874	29,735
Healthcare	40,426	1,199	41,625	29,615	897	30,512
Information technology	24,636	731	25,367	30,534	925	31,459
Services	31,212	926	32,138	25,316	767	26,083
Telecommunications/utilities	24,270	720	24,990	24,355	738	25,093
Other	16,455	488	16,943	11,420	346	11,766
Real estate investment trusts	5,779	171	5,950	6,572	199	6,771
Mutual funds	76,764	22,495	99,259	67,749	17,802	85,551
Government fixed income securities	34,495	1,023	35,518	18,663	565	19,228
Total Level 1 Assets (1)	$402,478	$32,154	$434,632	$350,915	$26,379	$377,294

	December 31, 2013			December 31, 2012		
	Qualified Retirement Plan	PBOP	Total	Qualified Retirement Plan	PBOP	Total
Level 2 – Significant other observable inputs						
Commercial paper	$ 1,411	$ 42	$ 1,453	$ 635	$ 19	$ 654
Government fixed income and mortgage backed securities	51,434	1,525	52,959	42,997	1,302	44,299
Corporate fixed income securities						
Asset-backed and mortgage-backed	12,998	385	13,383	16,637	504	17,141
Banking	19,004	564	19,568	17,966	544	18,510
Insurance	6,481	192	6,673	4,737	144	4,881
Utilities	5,278	156	5,434	4,107	124	4,231
Other	25,212	748	25,960	24,188	732	24,920
Pooled funds and mutual funds	8,111	1,150	9,261	20,636	1,789	22,425
State and local obligations	1,370	41	1,411	1,273	39	1,312
Total Level 2 assets (2)	$131,299	$ 4,803	$136,102	$133,176	$ 5,197	$138,373
Level 3 – Significant unobservable inputs						
Commingled equity funds	$189,452	$ 5,618	$195,070	$123,719	$ 3,748	$127,467
Total Level 3 assets (3)	$189,452	$ 5,618	$195,070	$123,719	$ 3,748	$127,467
Total Plan assets at fair value	$723,229	$42,575	$765,804	$607,810	$35,324	$643,134
Insurance company general account contracts (4)	4,296	—	4,296	4,626	—	4,626
Total Plan assets (5)	$727,525	$42,575	$770,100	$612,436	$35,324	$647,760

(1) Common stock, Real Estate Investment Trusts, Mutual funds, and U.S. Government securities listed or regularly traded on a national securities exchange are valued at quoted market prices as of the last business day of the calendar year.

The Mutual funds category above is an intermediate-term bond fund whose manager employs multiple concurrent strategies and takes only moderate risk in each, thereby reducing the risk of poor performance arising from any single source, and a balanced fund that invests in a diversified portfolio of common stocks, preferred stocks and fixed-income securities. Strategies utilized by the bond fund include duration management, yield curve or maturity structuring, sector rotation, and all bottom-up techniques including in-house credit and quantitative research. Strategies employed by the balanced fund include pursuit of regular income, conservation of principal, and an opportunity for long-term growth of principal and income.

(2) The fair value of investments in debt securities with remaining maturities of one year or more is determined by dealers who make markets in such securities or by an independent pricing service, which considers yield or price of bonds of comparable quality, coupon, maturity, and type.

The pooled funds and mutual funds are two collective short-term funds that invest in Treasury bills and money market funds. These funds are used as a temporary cash repository for the pension plan's various investment managers.

(3) Assets not considered Level 1 or Level 2 are valued using assumptions based on the best information available under the circumstances, such as investment manager pricing.

The commingled equity funds include private equity funds that invest in international securities (predominately Level 1 assets) regularly traded on securities exchanges. These funds are shown in the above table at net asset value. Investment strategies employed by the funds include:

- Investing in various industries with growth and reasonable valuations, avoiding highly cyclical industries
- Diversification by country, limiting exposure in any one country
- Emerging markets

The terms and conditions under which shares in the commingled equity funds may be redeemed vary among the funds; the notice required ranges from one day to 30 days prior to the valuation date (month end). One of the commingled equity funds requires the payment of a minimal impact fee to be applied to redemptions and subscriptions of $5 million or greater; the relative fee diminishes the greater the transaction. Other such funds may impose fees to recover direct costs incurred by the fund at redemption, but are indeterminable prior to redemption.

(4) The insurance company general account contracts are annuity insurance contracts used to pay the pensions of employees who retired prior to 1989. The balance of the account disclosed in the above table is the contract value, which is the result of deposits, withdrawals, and interest credits.

(5) The assets in the above table exceed the market value of plan assets shown in the funded status table by $7,842,000 (qualified retirement plan – $7,581,000, PBOP – $261,000) and $2,760,000 (qualified retirement plan – $2,685,000, PBOP – $75,000) for 2013 and 2012, respectively, which includes a payable for securities purchased, partially offset by receivables for interest, dividends, and securities sold.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

(Thousands of dollars):	Commingled Equity Funds
Balance, December 31, 2011	$100,273
Actual return on plan assets:	
Relating to assets still held at the reporting date	21,552
Relating to assets sold during the period	342
Purchases	6,800
Sales	(1,500)
Settlements	—
Transfers in and/or out of Level 3	—
Balance, December 31, 2012	127,467
Actual return on plan assets:	
Relating to assets still held at the reporting date	21,903
Relating to assets sold during the period	—
Purchases	45,700
Sales	—
Settlements	—
Transfers in and/or out of Level 3	—
Balance, December 31, 2013	$195,070

Note 10 – Stock-Based Compensation

At December 31, 2013, the Company had three stock-based compensation plans: a stock option plan, a performance share stock plan which includes a cash award, and a restricted stock/unit plan. The table below shows total stock-based plan compensation expense, including the cash award, which was recognized in the consolidated statements of income (in thousands):

	2013	2012	2011
Stock-based compensation plan expense, net of related tax benefits	$8,012	$7,396	$7,262
Stock-based compensation plan related tax benefits	4,910	4,533	4,451

Under the option plan, the Company previously granted options to purchase shares of common stock to key employees and outside directors. The last option grants were in 2006 and no future grants are anticipated. Each option has an exercise price equal to the market price of Company common stock on the date of grant and a maximum term of ten years.

The following tables summarize Company stock option plan activity and related information (thousands of options):

	2013		2012		2011	
	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price	Number of options	Weighted-average exercise price
Outstanding at the beginning of the year	125	$28.13	177	$27.28	369	$28.04
Exercised during the year	(72)	28.44	(52)	25.25	(192)	28.75
Forfeited or expired during the year	(1)	33.07	—	—	—	—
Outstanding and exercisable at year end	52	$27.57	125	$28.13	177	$27.28

The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of outstanding and exercisable options, and options that were exercised, are presented in the table below (in thousands):

	2013	2012	2011
Outstanding and exercisable	$1,473	$1,788	$2,697
Exercised	1,402	928	1,949

	December 31, 2013	December 31, 2012	December 31, 2011
Market value of Southwest Gas stock	$55.91	$42.41	$42.49

The weighted-average remaining contractual life for outstanding options was 1.6 years for 2013. All outstanding options are fully vested and exercisable. The following table summarizes information about stock options outstanding at December 31, 2013 (thousands of options):

	Options Outstanding and Exercisable		
Range of Exercise Price	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price
$20.49 to $23.40	13	0.5 Years	$23.27
$25.00 to $26.10	18	1.5 Years	$25.74
$29.08 to $33.07	21	2.5 Years	$31.91

The Company received $2 million in cash from the exercise of options during 2013 and a corresponding tax benefit of $446,000 which was recorded in additional paid-in capital.

Under the performance share stock plan, the Company may issue performance shares to encourage key employees to remain in its employment and to achieve short-term and long-term performance goals. Plan participants are eligible to receive a cash bonus (i.e., short-term incentive) and performance shares (i.e., long-term incentive). The performance shares vest three years after grant (and are subject to a final adjustment as determined by the Board of Directors) and are then issued as common stock.

The Company awards restricted stock/units under the restricted stock/unit plan to attract, motivate, retain, and reward key employees with an incentive to attain high levels of individual performance and improved financial performance of the Company. The restricted stock/units vest 40% at the end of year one and 30% at the end of years two and three and are issued annually as common stock in accordance with the percentage vested. The restricted stock/unit plan was also established to attract, motivate, and retain experienced and knowledgeable independent directors. Vesting for grants to directors followed the vesting schedule for employees; however, beginning with grants in 2012, the directors' restricted stock/units vest immediately upon grant. The issuance of common stock for directors occurs when their service on the Board ends.

The following table summarizes the activity of the performance share stock and restricted stock/unit plans as of December 31, 2013 (thousands of shares):

	Performance Shares	Weighted-average grant date fair value	Restricted Stock/Units	Weighted-average grant date fair value
Nonvested/unissued at beginning of year	348	$36.03	207	$37.18
Granted	106	44.83	100	44.83
Dividends	8		7	
Forfeited or expired	(3)	39.74	(1)	41.66
Vested and issued*	(136)	27.56	(68)	35.59
Nonvested/unissued at December 31, 2013	323	$39.16	245	$38.00

* Includes shares for retiree payouts and those converted for taxes.

The average grant date fair value of performance shares and restricted stock/units granted in 2012 and 2011 was $41.34 and $37.87, respectively.

As of December 31, 2013, total compensation cost related to nonvested performance shares and restricted stock/units not yet recognized is $3 million.

Note 11 – Income Taxes

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various states. The Company is subject to examinations by the Internal Revenue Service for years after 2009, and is subject to examination by the various state taxing authorities for years after 2008.

The Company recognizes interest expense and income and penalties related to income tax matters in income tax expense. Tax-related interest income included in income tax expense in the consolidated statements of income is shown in the table below (in thousands):

	2013	2012	2011
Tax-related interest income	$—	$24	$100

The Company had no uncertain tax liabilities at December 31, 2013, nor at any time during 2013. The Company expects no change in unrecognized tax benefits in the next twelve months.

Income tax expense (benefit) consists of the following (thousands of dollars):

Year Ended December 31,	2013	2012	2011
Current:			
Federal	$ 3,549	$ 2,296	$ (265)
State	5,107	5,744	2,122
	8,656	8,040	1,857
Deferred:			
Federal	67,414	65,551	58,584
State	1,872	1,685	2,862
	69,286	67,236	61,446
Total income tax expense	$77,942	$75,276	$63,303

Deferred income tax expense (benefit) consists of the following significant components (thousands of dollars):

Year Ended December 31,	2013	2012	2011
Deferred federal and state:			
Property-related items	$62,737	$64,249	$51,710
Purchased gas cost adjustments	16,189	1,755	(92)
Employee benefits	(2,769)	564	11,766
All other deferred	(6,010)	1,529	(1,070)
Total deferred federal and state	70,147	68,097	62,314
Deferred ITC, net	(861)	(861)	(868)
Total deferred income tax expense	$69,286	$67,236	$61,446

A reconciliation of the federal statutory rate to the consolidated effective tax rate for 2011, 2012, and 2013 (and the sources of these differences and the effect of each) are summarized as follows:

Year Ended December 31,	2013	2012	2011
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %
Net state taxes	2.4	2.6	2.7
Property-related items	0.1	0.2	0.2
Effect of income tax settlements	—	—	(0.9)
Tax credits	(0.4)	(0.4)	(0.6)
Company owned life insurance	(2.1)	(1.3)	(0.1)
All other differences	—	0.1	(0.1)
Consolidated effective income tax rate	35.0%	36.2%	36.2%

Deferred tax assets and liabilities consist of the following (thousands of dollars):

December 31,	2013	2012
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 2,679	$ 3,211
Employee benefits	25,591	27,097
Alternative minimum tax credit	19,739	18,467
Net operating losses and credits	15,113	36,206
Interest rate swap	9,893	11,164
Other	22,334	17,866
Valuation allowance	(200)	(141)
	95,149	113,870
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	694,024	652,380
Regulatory balancing accounts	18,688	2,498
Property-related items previously flowed through	836	1,729
Unamortized ITC	4,271	5,131
Debt-related costs	4,713	4,602
Other	15,898	16,626
	738,430	682,966
Net deferred tax liabilities	$643,281	$569,096
Current	$ (31,130)	$ (47,088)
Noncurrent	674,411	616,184
Net deferred tax liabilities	$643,281	$569,096

At December 31, 2013, the Company has a federal net operating loss carryforward of $43 million which expires in 2031. At December 31, 2013, the Company also has federal general business credits of $576,000, which begin to expire in 2031. The Company also has federal net capital loss carryforwards of $494,000, which begin to expire in 2016.

Final and Proposed Income Tax Regulations. In September 2013, the United States Department of the Treasury and the Internal Revenue Service ("IRS") issued final and proposed regulations for the tax treatment of tangible property. The final regulations include standards for determining whether and when a taxpayer must capitalize costs incurred in acquiring, maintaining, or improving tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, and may be adopted in earlier years under certain circumstances. Proposed regulations were also released that revise the rules for dispositions of tangible property and general asset accounts. The proposed regulations addressing dispositions and general asset accounts are also expected (when finalized) to be effective for tax years starting on or after January 1, 2014, and may be adopted in earlier years under certain circumstances. The Company expects the IRS to issue natural gas industry guidance which will facilitate its analysis regarding the regulations' impact on natural gas distribution networks. Based upon preliminary analysis of the final and proposed regulations, and in anticipation of specific guidance for the natural gas industry, the Company expects the regulations could result in a modest acceleration of tax deductibility, and the deferral of tax payments.

Note 12 – Derivatives and Fair Value Measurements

Derivatives. In managing its natural gas supply portfolios, Southwest has historically entered into fixed- and variable-price contracts, which qualify as derivatives. Additionally, Southwest utilizes fixed-for-floating swap contracts ("Swaps") to supplement its fixed-price contracts. The fixed-price contracts, firm commitments to purchase a fixed amount of gas in the future at a fixed price, qualify for the normal purchases and normal sales exception that is allowed for contracts that are probable of delivery in the normal course of business, and are exempt from fair value reporting. The variable-price contracts have no significant market value. The Swaps are recorded at fair value.

As part of the most recent Nevada Annual Rate Adjustment and associated stipulation in Nevada, the Company decided to suspend further swaps and fixed-price purchases pursuant to the Volatility Mitigation Program for its Nevada service territories. The decision will not impact previously executed purchase arrangements. The Company, along with its regulators, will continue to evaluate this strategy in light of prevailing or anticipated changing market conditions.

The fixed-price contracts and Swaps are utilized by Southwest under its volatility mitigation programs to effectively fix the price on a portion (for the 2013/2014 heating season, ranging from 25% to 35%, depending on the jurisdiction) of its natural gas supply portfolios. The maturities of the Swaps highly correlate to forecasted purchases of natural gas, during time frames ranging from January 2014 through March 2016. Under such contracts, Southwest pays the counterparty a fixed rate and receives from the counterparty a floating rate per MMBtu ("dekatherm") of natural gas. Only the net differential is actually paid or received. The differential is calculated based on the notional amounts under the contracts, which are detailed in the table below (thousands of dekatherms):

	December 31, 2013	December 31, 2012
Contract notional amounts	13,571	14,579

Southwest does not utilize derivative financial instruments for speculative purposes, nor does it have trading operations.

The following table sets forth the gains and (losses) recognized on the Company's Swaps (derivatives) for the years ended December 31, 2013, 2012, and 2011 and their location in the Consolidated Statements of Income (thousands of dollars):

Gains (losses) recognised in income for derivatives not designated as hedging instruments:
(Thousands of dollars)

Instrument	Location of Gain or (Loss) Recognized in Income on Derivative	2013	2012	2011
Swaps	Net cost of gas sold	$ 976	$(4,854)	$(18,201)
Swaps	Net cost of gas sold	(976)*	4,854*	18,201*
Total		$ —	$ —	$ —

* Represents the impact of regulatory deferral accounting treatment under U.S. GAAP for rate-regulated entities.

In January 2010, Southwest entered into two FSIRS (both, designated cash flow hedges) to partially hedge the risk of interest rate variability during the period leading up to the planned issuance of fixed-rate debt to replace maturing debt. The first FSIRS terminated in December 2010. The second FSIRS had a notional amount of $100 million and terminated in March 2012 concurrent with the related issuance of $250 million of 3.875% 10-year senior notes. At settlement of the second FSIRS, Southwest paid an aggregate $21.8 million to the counterparties. No gain or loss (ineffective portion) was recognized in income for either FSIRS during any period, including the period presented in the following table.

Gains (losses) recognised in other comprehensive income for derivatives designated as cash flow hedging instruments:

(Thousands of dollars)	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Amount of gain/(loss) realized/unrealized on FSIRS recognized in other comprehensive income on derivative	$—	$2,959	$(17,958)

The following table sets forth the fair values of the Company's Swaps and their location in the Consolidated Balance Sheets (thousands of dollars):

Fair values of derivatives not designated as hedging instruments:

December 31, 2013 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 257	$ (77)	$ 180
Swaps	Prepaids and other current assets	1,054	(253)	801
Swaps	Other current liabilities	126	(282)	(156)
Swaps	Other deferred credits	7	(11)	(4)
Total		$1,444	$ (623)	$ 821

December 31, 2012 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Deferred charges and other assets	$ 132	$ (126)	$ 6
Swaps	Other current liabilities	391	(2,467)	(2,076)
Swaps	Other deferred credits	233	(552)	(319)
Total		$ 756	$(3,145)	$(2,389)

The estimated fair values of the natural gas derivatives were determined using future natural gas index prices (as more fully described below). The Company has master netting arrangements with each counterparty that provide for the net settlement of all contracts through a single payment. As applicable, the Company has elected to reflect the net amounts in its balance sheets. The Company had no outstanding collateral associated with the Swaps during either period shown in the above table.

Pursuant to regulatory deferral accounting treatment for rate-regulated entities, Southwest records the unrealized gains and losses in fair value of the Swaps as a regulatory asset and/or liability. When the Swaps mature, Southwest reverses any prior positions held and records the settled position as an increase or decrease of purchased gas under the related purchased gas adjustment ("PGA") mechanism in determining its deferred PGA balances. Neither changes in fair value, nor settled amounts, of Swaps have a direct effect on earnings or other comprehensive income.

The following table shows the amounts Southwest paid to and received from counterparties for settlements of matured Swaps.

	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011
(Thousands of dollars)			
Paid to counterparties	$3,148	$14,843	$17,283
Received from counterparties	$ 915	$ 634	$ —

The following table details the regulatory assets/(liabilities) offsetting the derivatives at fair value in the Consolidated Balance Sheets (thousands of dollars).

December 31, 2013 Instrument	Balance Sheet Location	Net Total
Swaps	Other deferred credits	$ (180)
Swaps	Other current liabilities	(801)
Swaps	Prepaids and other current assets	156
Swaps	Deferred charges and other assets	4

December 31, 2012 Instrument	Balance Sheet Location	Net Total
Swaps	Other deferred credits	$ (6)
Swaps	Prepaids and other current assets	2,076
Swaps	Deferred charges and other assets	319

Fair Value Measurements. The estimated fair values of Southwest's Swaps were determined at December 31, 2013 and 2012 using New York Mercantile Exchange ("NYMEX") futures settlement prices for delivery of natural gas at Henry Hub adjusted by the price of NYMEX ClearPort basis Swaps, which reflect the difference between the price of natural gas at a given delivery basin and the Henry Hub pricing points. These Level 2 inputs (inputs, other than quoted prices, for similar assets or liabilities) are observable in the marketplace throughout the full term of the Swaps, but have been credit-risk adjusted with no significant impact to the overall fair value measure.

The following table sets forth, by level within the three-level fair value hierarchy that ranks the inputs used to measure fair value by their reliability, the Company's financial assets and liabilities that were accounted for at fair value (see **Note 9 – Pension and Other Post Retirement Benefits** for definitions of the levels of the fair value hierarchy):

Level 2 – Significant other observable inputs

	December 31, 2013	December 31, 2012
(Thousands of dollars)		
Assets at fair value:		
Prepaids and other current assets - Swaps	$ 801	$ —
Deferred charges and other assets - Swaps	180	6
Liabilities at fair value:		
Other current liabilities - Swaps	(156)	(2,076)
Other deferred credits - Swaps	(4)	(319)
Net Assets (Liabilities)	$ 821	$(2,389)

No financial assets or liabilities accounted for at fair value fell within Level 1 or Level 3 of the fair value hierarchy.

Note 13 – Segment Information

Company operating segments are determined based on the nature of their activities. The natural gas operations segment is engaged in the business of purchasing, distributing, and transporting natural gas. Revenues are generated from the distribution and transportation of natural gas. The construction services segment is primarily engaged in the business of providing utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

The accounting policies of the reported segments are the same as those described within **Note 1 – Summary of Significant Accounting Policies**. NPL accounts for the services provided to Southwest at contractual (market) prices at contract inception. Accounts receivable for these services, which are not eliminated during consolidation, are presented in the table below (in thousands).

	December 31, 2013	December 31, 2012
Accounts receivable for NPL services	$10,787	$8,179

The financial information pertaining to the natural gas operations and construction services segments for each of the three years in the period ended December 31, 2013 is as follows (thousands of dollars):

2013	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,300,154	$562,475		$1,862,629
Intersegment sales	—	88,153		88,153
Total	$1,300,154	$650,628		$1,950,782
Interest revenue	$ 456	$ 5		$ 461
Interest expense	$ 62,555	$ 1,145		$ 63,700
Depreciation and amortization	$ 193,848	$ 42,969		$ 236,817
Income tax expense	$ 65,377	$ 12,565		$ 77,942
Segment net income	$ 124,169	$ 21,151		$ 145,320
Segment assets	$4,272,029	$293,811	$(666)	$4,565,174
Capital expenditures	$ 314,578	$ 49,698		$ 364,276

2012	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,321,728	$522,676		$1,844,404
Intersegment sales	—	83,374		83,374
Total	$1,321,728	$606,050		$1,927,778
Interest revenue	$ 915	$ 9		$ 924
Interest expense	$ 66,957	$ 1,063		$ 68,020
Depreciation and amortization	$ 186,035	$ 37,387		$ 223,422
Income tax expense	$ 64,973	$ 10,303		$ 75,276
Segment net income	$ 116,619	$ 16,712		$ 133,331
Segment assets	$4,204,948	$283,109		$4,488,057
Capital expenditures	$ 308,951	$ 86,761		$ 395,712

2011	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,403,366	$391,701		$1,795,067
Intersegment sales	—	92,121		92,121
Total	$1,403,366	$483,822		$1,887,188
Interest revenue	$ 465	$ 20		$ 485
Interest expense	$ 68,777	$ 825		$ 69,602
Depreciation and amortization	$ 175,253	$ 25,216		$ 200,469
Income tax expense	$ 49,576	$ 13,727		$ 63,303
Segment net income	$ 91,420	$ 20,867		$ 112,287
Segment assets	$4,048,613	$227,394		$4,276,007
Capital expenditures	$ 305,542	$ 75,449		$ 380,991

(a) Construction services segment assets include income taxes payable of $666,000 in 2013, which was netted against gas operations segment income taxes receivable, net during consolidation.

Note 14 – Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
(Thousands of dollars, except per share amounts)				
2013				
Operating revenues	$613,505	$411,574	$387,346	$538,357
Operating income	138,394	28,908	6,141	100,772
Net income (loss)	80,674	10,067	(3,057)	57,189
Net income (loss) attributable to Southwest Gas Corporation	80,773	10,108	(2,864)	57,303
Basic earnings (loss) per common share*	1.75	0.22	(0.06)	1.24
Diluted earnings (loss) per common share*	1.73	0.22	(0.06)	1.22
2012				
Operating revenues	$657,645	$409,768	$371,799	$488,566
Operating income	134,623	15,380	6,310	115,211
Net income (loss)	78,835	(3,888)	(4,414)	62,106
Net income (loss) attributable to Southwest Gas Corporation	78,919	(3,676)	(4,305)	62,393
Basic earnings (loss) per common share*	1.71	(0.08)	(0.09)	1.35
Diluted earnings (loss) per common share*	1.70	(0.08)	(0.09)	1.34

	Quarter Ended			
	March 31	June 30	September 30	December 31
(Thousands of dollars, except per share amounts)				
2011				
Operating revenues	$628,440	$388,505	$352,592	$517,651
Operating income	126,335	20,568	1,253	101,924
Net income (loss)	68,354	4,013	(15,747)	55,143
Net income (loss) attributable to Southwest Gas Corporation	68,549	4,055	(15,641)	55,324
Basic earnings (loss) per common share*	1.50	0.09	(0.34)	1.20
Diluted earnings (loss) per common share*	1.48	0.09	(0.34)	1.19

* The sum of quarterly earnings (loss) per average common share may not equal the annual earnings (loss) per share due to the ongoing change in the weighted-average number of common shares outstanding.

The demand for natural gas is seasonal, and it is the opinion of management that comparisons of earnings for interim periods do not reliably reflect overall trends and changes in the operations of the Company. Also, the timing of general rate relief can have a significant impact on earnings for interim periods. See Management's Discussion and Analysis for additional discussion of operating results.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined by Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Company management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of internal control over financial reporting based on the "*Internal Control – Integrated Framework*" issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based upon the Company's evaluation under such framework, Company management concluded that the internal control over financial reporting was effective as of December 31, 2013. The effectiveness of the Company's internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 27, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwest Gas Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of cash flows and of equity present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in 1992. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Las Vegas, Nevada
February 27, 2014

Board of Directors and Officers

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Las Vegas, Nevada
Executive Vice President and
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Boyd Gaming Corporation

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Retired Construction Executive

Stephen C. Comer
Las Vegas, Nevada
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Deloitte & Touche LLP

LeRoy C. Hanneman, Jr.
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Southwest Gas Corporation

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Executive Vice President

Roy R. Centrella
Senior Vice President/Chief
Financial Officer

Eric DeBonis
Senior Vice President/
Operations

Karen S. Haller
Senior Vice President/General
Counsel and Corporate Secretary

Laura Lopez Hobbs
Senior Vice President/Human
Resources and Administration

Edward A. Janov
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Corporate Development

Anita M. Romero
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Technology

Justin L. Brown
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Garold L. Clark
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Arizona Division

Jose L. Esparza, Jr.
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Bradford T. Harris
Vice President/Southern
California Division

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Vice President/Finance/Treasurer

Gregory J. Peterson
Vice President/Controller/
Chief Accounting Officer

Jerome T. Schmitz
Vice President/Engineering

Christopher W. Sohus
Vice President/Southern
Nevada Division

Julie M. Williams
Vice President/Northern
Nevada Division

Shareholder Information

Stock Listing Information
Southwest Gas Corporation (the "Company") common stock is listed on the New York Stock Exchange under the ticker symbol "SWX." Quotes may be obtained in daily financial newspapers or some local newspapers where it is sometimes listed under "SoWestGas," or on our website at www.swgas.com.

Annual Meeting
The Annual Meeting of Shareholders will be held on May 8, 2014 at 10:00 a.m. at Cili Restaurant at
Bali Hai Golf Club
5160 Las Vegas Blvd., South
Las Vegas, NV 89119

Dividend Reinvestment and Stock Purchase Plan
Our Dividend Reinvestment and Stock Purchase Plan (DRSPP) provides the Company's shareholders, natural gas customers, employees, and residents of Arizona, California and Nevada with a simple and convenient method of purchasing the Company's common stock and investing cash dividends in additional shares without payment of brokerage commissions.
DRSPP features include a minimum initial investment of $250, up to a maximum of $100,000 annually, automatic investing, no commissions on purchases, and the safekeeping of common stock certificates.
For more information contact:
Wells Fargo Shareowner Services
P.O. Box 64856
St. Paul, MN 55164-0874
or call 1-800-331-1119

Dividends
Dividends on common stock are declared quarterly by the Board of Directors and are generally payable on the first day of March, June, September, and December.

Investor Relations
The Company is committed to providing relevant and complete investment information to shareholders, individual investors and members of the investment community. Copies of the Company's 2013 Annual Report on Form 10-K, without exhibits, as filed with the Securities and Exchange Commission may be obtained from our Corporate Secretary upon request free of charge. Additional requests of a financial nature should be directed to Kenneth J. Kenny, Investor Relations, Southwest Gas Corporation, P. O. Box 98510, Las Vegas, NV 89193-8510 or by calling (702) 876-7237.

Additional Company information is available at www.swgas.com. For non-financial information, please call (702) 876-7011.

Transfer Agent and Registrar
Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-9942

Auditors
PricewaterhouseCoopers LLP
3800 Howard Hughes Parkway
Suite 650
Las Vegas, NV 89169

Forward-Looking Statements
This Annual Report contains forward-looking statements regarding the Company's current expectations. These statements are subject to a variety of risks that could cause actual results to differ materially from expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the Company's Annual Report on Form 10-K for the year 2013.

SOUTHWEST GAS

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