Fostering Strong Roots

Southwest Gas Corporation
2012 Annual Report

Despite the economic storm of the past several years, Southwest Gas stands strong. We attribute our stability to our strong roots in service, safety, and reliability - guiding principles to our business.

Our people

We are dedicated to serving our customers and our community well - and safely. Nothing is stronger than our employees' commitment to the highest level of customer service and safety standards.

SOUTHWEST GAS

Our product

Our product is clean, abundant, and American. It is the perfect foundation fuel to meet our environmental challenges and secure our energy independence. With a supply picture that's never been brighter, natural gas delivers stable pricing and performance reliability for our customers.

Our commitment

We want to improve energy efficiencies, reduce customer costs, reduce greenhouse emissions and increase our customers' energy security. With our commitment to service, safety, and reliability, we continue to grow deep roots in the communities we serve.

Fellow shareholder:

It is a great time to be in the natural gas distribution business. Natural gas is plentiful, prices are reasonable, the nation is increasingly embracing its importance as an energy source, and we believe the environment is better off because of it. At Southwest Gas, we have never wavered in extolling the benefits of this precious natural resource, and we believe our track record demonstrates our success in the natural gas distribution business.

Over the past several years, the Board of Directors and management have consistently adhered to a strategy that emphasizes the core fundamentals of our business. We firmly believe that this focus drives increased value to shareholders and measurable benefits to our customers. In this letter, we will review several key performance metrics over the last decade that demonstrate how this strategy has benefitted shareholders and customers alike.

We are pleased to report 2012 earnings per share of $2.89, an 18% increase over the $2.45 reported in 2011 and the highest in the Company's history. Earnings were driven by strong performance in the natural gas segment of our business, which contributed $116.6 million in net income in 2012, compared to $91.4 million in the prior year; and a 2012 contribution of $16.7 million in net income from NPL Construction Co. (NPL), our pipeline construction subsidiary, compared to $20.9 million in 2011. Additionally, for the seventh straight year, the Board recently approved an increase in the annualized dividend on common stock, from $1.18 per share to $1.32 per share.

The Company ended 2012 with a common stock price of $42.41 per share. Over the past decade, our patient investors have been rewarded. The Company's stock price appreciated more than 80%, and considering dividend reinvestments, long-term investors have earned a compound weighted average annual return of 9.49%. And over this same time period, net income has more than tripled and earnings per share more than doubled.

The road to improved operating results has not always been smooth, as the Company has experienced significant volatility in its earnings during the last decade. However, by working with our regulators in a transparent

and collaborative way, the Company improved operating margins and rate designs which are mitigating the volatility in earnings. 2012 marked the first full year that the Company experienced fully decoupled rate designs in all regulatory jurisdictions. This has been a true “win-win” for both customers and shareholders: decoupled rate designs can improve credit metrics, lower interest expense, stabilize customer bills, reduce periodic rate case requests, and allow the Company to embrace energy efficiency on behalf of customers without hampering the recovery of service costs. Looking forward, we expect these approved rate designs to result in improved stability of revenues and cash flows, and decreased volatility in our customers’ bills.

We have made great strides in strengthening our balance sheet and credit ratings. Ten years ago, the equity component of our capital structure was below 35% and our credit ratings were low investment grade. Through improved earnings and cash flows over the last decade, the Company’s equity ratio improved to 50% of the total capital structure. The national credit rating agencies have recognized our improved credit profile which is reflected in our credit ratings of A- (Fitch), Baa1 (Moody’s), and BBB+ (Standard & Poor’s). These credit rating improvements, coupled with very favorable market interest rates, allowed the Company to refinance several series of long-term debt obligations at very attractive rates, benefitting both customers and shareholders. In fact, as recently as 2008, gas segment financing costs were $91 million, compared to $67 million in 2012, a 26% reduction.

We are fortunate to be situated in the southwestern part of the United States where customer growth has played a major role in our success. We now serve over 400,000 more customers than we did ten years ago. And while the recession hit our region hard causing the growth rate to slow, it never stopped. Between 2011 and 2012 we billed an average of 20,000 more customers per month. We are optimistic that economic conditions will continue to rebound and an improved rate of growth will follow. Although improvement in economic conditions remains slow, recent positive trends in unemployment rates, housing prices, and other economic indicators provide evidence we are on a better track. The Company expects customer growth in 2013 to approximate that of the prior year.

Cost containment and customer satisfaction are core values at Southwest Gas. These strategies may appear to conflict with one another, but when you stay focused on both, positive results are possible for both customers and shareholders. Over the past decade, our operating costs per customer, on average, increased about 1% per year, which is less than half the 2.4% average inflation rate during the same period. We have accomplished this by embracing technology and improving operating processes to work smarter and more efficiently. Over the last ten years, our customer-to-employee ratio, a key industry measure of productivity, increased from 571 to 1 to 836 to 1, or 46%. Meanwhile, we remained focused on providing quality customer service resulting in customer satisfaction that consistently averaged between 90% and 95%. None of these positive measures would have been possible without the hard work and innovation of our dedicated employees.

Aging natural gas infrastructure is a common concern throughout the country and one which utilities take very seriously. At Southwest Gas, we are an industry leader in distribution system integrity management practices. In recent years, we have devoted more than 25% of our capital budget to pipe replacement activities, including 43% during 2012. We expect to continue to devote significant capital to this effort through the foreseeable future. One of our strategic initiatives is to work with regulators to provide cost recovery mechanisms in between rate cases to mitigate regulatory lag on what would otherwise be non-revenue producing investments. This will be a continued focus for us going forward.

NPL, our pipeline construction subsidiary, had their second highest earnings year in 2012. As one of the few entities in its industry with a national breadth, NPL is benefitting from the extensive pipe replacement activities which are occurring across the country. They experienced rapid growth during the last few years and anticipate continued opportunity in the future as well. As a result, during 2012, NPL made structural and transitional changes to match the increased size of the business. We believe NPL is well positioned to capitalize on infrastructure replacement and new construction opportunities for many years to come.

In its ongoing review of dividend policy, the Board determined that it is appropriate and in the best interests of shareholders to increase the dividend on common stock. At its February 26, 2013 meeting, the Board acted to raise the annualized dividend on common stock from $1.18 per share to $1.32, an 11.9% increase. In reviewing dividend policy, the Board considers the adequacy and sustainability of the earnings and cash flows of the Company and its subsidiaries; the strength of the Company's capital structure; the sustainability of the dividend through business cycles; and whether the dividend is within a normal payout range for our industry. Looking 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 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.

As we look back on the last ten years, the Company has significantly advanced the interests of our shareholders and customers by concentrating on the core fundamentals of our business. Our progress has been marked by focus, determination, consistency, and patience. We believe that same emphasis can bring continued success going forward, and we do not expect to stray far from the things we do best. Having an abundant, reasonably-priced and versatile energy source to sell only buoys our optimism. Our message has been a consistent one, and while you can't predict the future from the past, you can expect us to remain focused on working collaboratively with regulators, pursuing operating efficiencies and productivity, seeking prudent growth opportunities, and striving to exceed customer expectations. It is a story to us that never gets old and one we expect will continue to produce a positive outcome for our shareholders.

Michael J. Melarkey
Chairman of the Board

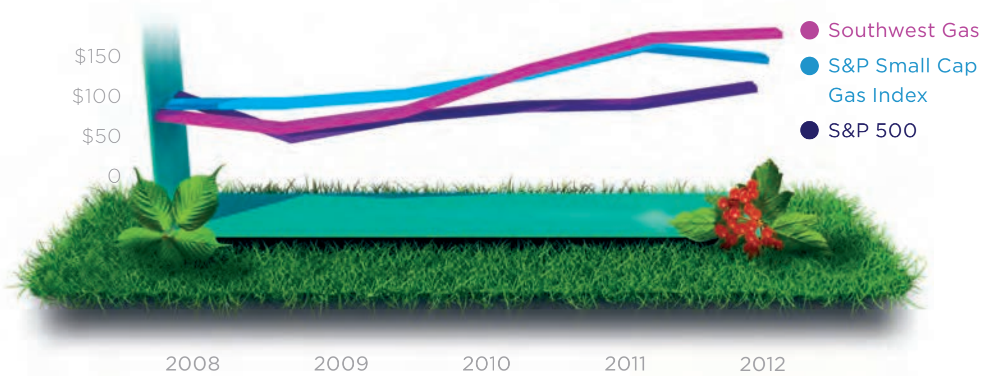
Jeffrey W. Shaw
President and Chief Executive Officer

Customers Per Employee

Stock Prices and Trading Volume

	2008	2009	2010	2011	2012
High	H: $33.29	H: $29.48	H: $37.25	H: $43.20	H: $46.08
Low	L: $21.11	L: $17.08	L: $26.28	L: $32.12	L: $39.01
Volume (in hundreds)	V: 706,189	V: 678,866	V: 464,009	V: 569,341	V: 432,089

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.

Margin by Customer Class 2012

Residential 69% Small Commercial 16% Large Commercial 3%
Transportation 11% Industrial/Other 1%

Customers by Division 2012

Southern Nevada 33% Central Arizona 32% Southern Arizona 21%
Southern California 7% Northern Nevada 7%

Financial Section

Consolidated Selected Financial Statistics

Year Ended December 31,	2012	2011	2010	2009	2008
(Thousands of dollars, except per share amounts)					
Operating revenues	$1,927,778	$1,887,188	$1,830,371	$1,893,824	$2,144,743
Operating expenses	1,656,254	1,637,108	1,598,254	1,685,433	1,936,881
Operating income	$ 271,524	$ 250,080	$ 232,117	$ 208,391	$ 207,862
Net income	$ 133,331	$ 112,287	$ 103,877	$ 87,482	$ 60,973
Total assets at year end	$4,488,057	$4,276,007	$3,984,193	$3,906,292	$3,820,384
Capitalization at year end					
Total equity	$1,308,498	$1,225,031	$1,166,996	$1,102,086	$1,037,841
Subordinated debentures	—	—	—	100,000	100,000
Long-term debt, excluding current maturities	1,268,373	930,858	1,124,681	1,169,357	1,185,474
	$2,576,871	$2,155,889	$2,291,677	$2,371,443	$2,323,315
Current maturities of long-term debt	$ 50,137	$ 322,618	$ 75,080	$ 1,327	$ 7,833
Common stock data					
Common equity percentage of capitalization	50.8%	56.8%	50.9%	46.5%	44.7%
Return on average common equity	10.4%	9.3%	9.1%	8.1%	6.0%
Basic earnings per share	$ 2.89	$ 2.45	$ 2.29	$ 1.95	$ 1.40
Diluted earnings per share	$ 2.86	$ 2.43	$ 2.27	$ 1.94	$ 1.39
Dividends declared per share	$ 1.18	$ 1.06	$ 1.00	$ 0.95	$ 0.90
Payout ratio	41%	43%	44%	49%	64%
Book value per share at year end	$ 28.39	$ 26.68	$ 25.60	$ 24.44	$ 23.48
Market value per share at year end	$ 42.41	$ 42.49	$ 36.67	$ 28.53	$ 25.22
Market value per share to book value per share	149%	159%	143%	117%	107%
Common shares outstanding at year end (000)	46,148	45,956	45,599	45,092	44,192
Number of common shareholders at year end	16,028	16,834	17,821	20,489	22,244
Ratio of earnings to fixed charges	3.61	3.21	2.87	2.46	2.01

Natural Gas Operations

Year Ended December 31,	2012	2011	2010	2009	2008
(Thousands of dollars)					
Sales	$1,238,513	$1,329,512	$1,438,809	$1,547,081	$1,728,924
Transportation	83,215	73,854	73,098	67,762	62,471
Operating revenue	1,321,728	1,403,366	1,511,907	1,614,843	1,791,395
Net cost of gas sold	479,602	613,489	736,175	866,630	1,055,977
Operating margin	842,126	789,877	775,732	748,213	735,418
Expenses					
Operations and maintenance	369,979	358,498	354,943	348,942	338,660
Depreciation and amortization	186,035	175,253	170,456	166,850	166,337
Taxes other than income taxes	41,728	40,949	38,869	37,318	36,780
Operating income	$ 244,384	$ 215,177	$ 211,464	$ 195,103	$ 193,641
Contribution to consolidated net income	$ 116,619	$ 91,420	$ 91,382	$ 79,420	$ 53,747
Total assets at year end	$4,204,948	$4,048,613	$3,845,111	$3,782,913	$3,680,327
Net gas plant at year end	$3,343,794	$3,218,944	$3,072,436	$3,034,503	$2,983,307
Construction expenditures and property additions	$ 308,951	$ 305,542	$ 188,379	$ 212,919	$ 279,254
Cash flow, net					
From operating activities	$ 344,441	$ 216,745	$ 342,522	$ 371,416	$ 261,322
From (used in) investing activities	(296,886)	(289,234)	(178,685)	(265,850)	(237,093)
From (used in) financing activities	(43,453)	(2,327)	(107,779)	(81,744)	(34,704)
Net change in cash	$ 4,102	$ (74,816)	$ 56,058	$ 23,822	$ (10,475)
Total throughput (thousands of therms)					
Residential	655,046	718,765	704,693	669,736	704,986
Small commercial	270,665	303,923	300,940	294,225	314,555
Large commercial	116,582	112,256	111,833	117,241	125,121
Industrial/Other	47,830	50,208	58,922	72,623	97,702
Transportation	998,095	941,544	998,600	1,043,894	1,164,190
Total throughput	2,088,218	2,126,696	2,174,988	2,197,719	2,406,554
Weighted average cost of gas purchased ($/therm)	$ 0.42	$ 0.58	$ 0.62	$ 0.71	$ 0.84
Customers at year end	1,876,000	1,859,000	1,837,000	1,824,000	1,819,000
Employees at year end	2,245	2,298	2,349	2,423	2,447
Customer to employee ratio	836	809	782	753	743
Degree days – actual	1,740	2,002	1,998	1,824	1,902
Degree days – ten-year average	1,866	1,888	1,876	1,882	1,893

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, 2012, Southwest had 1,876,000 residential, commercial, industrial, and other natural gas customers, of which 1,010,000 customers were located in Arizona, 681,000 in Nevada, and 185,000 in California. Residential and commercial customers represented over 99% of the total customer base. During 2012, 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 operating margin changes are general rate relief, weather, conservation and efficiencies, and customer growth. Weather has traditionally been the primary reason for volatility in margin, which continued throughout 2011 with respect to Southwest's Arizona service territories. In January 2012, however, a full revenue decoupling mechanism, which includes a monthly weather adjuster, was implemented in the Arizona service territories. With this change, all of Southwest's service territories have decoupled rate structures, which are designed to mitigate the impacts of weather variability and conservation on margin and allow 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 18 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 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 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 86% 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,	2012	2011	2010
(In thousands, except per share amounts)			
Contribution to net income			
Natural gas operations	$116,619	$ 91,420	$ 91,382
Construction services	16,712	20,867	12,495
Consolidated	$133,331	$112,287	$103,877
Average number of common shares outstanding	46,115	45,858	45,405
Basic earnings per share			
Consolidated	$ 2.89	$ 2.45	$ 2.29
Natural Gas Operations			
Operating margin	$842,126	$789,877	$775,732

2012 Overview

Consolidated operating results for 2012 increased compared to 2011 due to improved operating results from the natural gas segment. Basic earnings per share were $2.89 in 2012 compared to basic earnings per share of $2.45 in 2011.

Natural gas operations highlights include the following:

- Operating margin increased $52 million, or 7%, compared to the prior year
- Operating expenses increased $23 million, or 4%, between years
- Net financing costs decreased $2 million between 2012 and 2011
- Other income increased $10 million between years
- Replacement of expiring credit facility with a new $300 million facility in March 2012
- Issued $250 million 3.875% Senior Notes in March 2012 with approximately $200 million of the net proceeds used to repay $200 million of 7.625% Senior Notes that matured in May 2012
- The Company's credit rating was upgraded from Baa2 to Baa1 by Moody's and from BBB+ to A- by Fitch, in March and May 2012, respectively
- Nevada general rate increase of $7 million was approved effective November 2012

Construction services highlights include the following:

- Revenues in 2012 increased $122 million, or 25%, compared to 2011
- Construction expenses increased $118 million or 28%, compared to 2011
- Replacement of a $30 million credit facility with a new $75 million facility in June 2012

Arizona Rate Relief. During 2012, Southwest realized $45 million of incremental operating margin from rate relief in its Arizona operating areas. See **Rates and Regulatory Proceedings** for additional information on the associated general rate case with new rates that were effective January 2012.

Weather and Conservation. Weather has traditionally been the primary reason for volatility in margin, which continued throughout 2011 with respect to Southwest's Arizona service territories. In January 2012, however, a full revenue decoupling mechanism, which includes a winter-period monthly weather adjuster, was implemented in the Arizona service territories for most customer classes. With this change, all of Southwest's service territories have decoupled rate structures, which are designed to mitigate the impacts of weather variability and conservation on margin and allow the Company to aggressively pursue energy efficiency initiatives on behalf of its customers.

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 is estimated to provide a 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. For northern Nevada, the Decision is estimated to provide 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. Approximately $2 million in incremental margin was recorded in the fourth quarter of 2012. Factoring in other aspects of the Decision, including lower depreciation rates, the Decision is 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. See **Rates and Regulatory Proceedings** for more information.

California General Rate Case. In December 2012, Southwest filed a general rate case application with the California Public Utilities Commission ("CPUC") requesting $11.6 million in annual rate increases for its California rate jurisdictions with a proposed effective date of January 2014. See **Rates and Regulatory Proceedings** for more information.

Customer Growth. Southwest added 17,000 net new customers over the last twelve months. First-time meter sets also approximated 17,000 during the year. Recently, Southwest has experienced customer growth in excess of first-time meter sets as meters on previously vacant homes return to service. Southwest estimates the remaining number of excess inactive meters is approximately 37,000 at December 31, 2012. Southwest projects customer growth associated with new meter sets of about 1% for 2013, along with a gradual return of customers associated with previously vacant homes.

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 $230 million at December 31, 2012. 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 $80 million at December 31, 2012 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. As indicated in Note 1, cash surrender values of COLI policies increased $6.6 million in 2012. Investment returns during 2012 were significantly higher than normal. In 2011, income from changes in the cash surrender value of COLI policies

and recognized death benefits was $700,000. Management currently expects average returns of $2 million to $4 million annually on the COLI policies, excluding any net death benefits recognized. Based on the current investment mix, both positive and negative deviations from expected levels are likely to continue.

Credit Facility and Commercial Paper Program. In March 2012, Southwest replaced its $300 million credit facility, which would have expired in May 2012, with a new $300 million facility that expires in March 2017. Southwest has a $50 million commercial paper program, which is supported by (and not incremental to) the credit facility. See Capital Resources and Liquidity for more information.

Liquidity. Southwest believes its liquidity position is solid. As noted above, 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. The maximum amount outstanding on the credit facility during 2012 was $130 million in the fourth quarter. At December 31, 2012, $91 million was outstanding on the long-term portion, and no borrowings were outstanding on the short-term portion of the credit facility. At December 31, 2012, the amount outstanding under the commercial paper program was $20 million.

Southwest also believes its ability to obtain funding for ongoing expenditures and future expansions is secure and adequate. Historically, Southwest has accessed the public debt markets for funding, most recently in March 2012 in connection with the issuance of $250 million of 3.875% Senior Notes. Southwest's solid liquidity position also provided an opportunity to redeem $12.4 million of 6.10% IDRBs and $14.3 million of 5.95% IDRBs in 2012. Each of these redemptions was at par. Southwest plans to redeem $30 million of 5.45% IDRBs and $15 million of 5.80% IDRBs at par in March 2013. Southwest has no subsequent long-term debt maturities until 2017.

Credit Rating Upgrades. Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings ("Fitch") upgraded the Company's senior unsecured rating to Baa1 from Baa2 in March 2012 and to A- from BBB+ in May 2012, respectively. See *Credits Ratings* for more information.

Loss on NPL Contract. In the first half of 2012, NPL recorded $18 million in losses on a large fixed-price pipe replacement contract in a single geographic location. A number of factors contributed to the loss on the contract, which was the largest fixed-price contract ever undertaken by NPL. Approved change orders during the fourth quarter of 2012 helped to reduce current-year losses on the contract to $15 million. At December 31, 2012, work on the contract is substantially complete with the exception of some restoration work. Since inception in 2011, NPL has recognized approximately $75 million of revenues on this contract, including $37 million in 2011. Construction costs recorded to date total approximately $85 million, including $32 million during 2011. No significant additional losses are anticipated on the remaining work to be performed, although no assurances can be provided that additional losses on this contract will not occur.

NPL has another contract with the same customer in the same geographical area with a fixed-price component of approximately $28 million. Work began in the middle of 2012 and will continue into 2013. Based on the progress to date and review of estimated costs to complete, management expects this contract to be marginally profitable overall.

Results of Natural Gas Operations

Year Ended December 31,	2012	2011	2010
(Thousands of dollars)			
Gas operating revenues	$1,321,728	$1,403,366	$1,511,907
Net cost of gas sold	479,602	613,489	736,175
Operating margin	842,126	789,877	775,732
Operations and maintenance expense	369,979	358,498	354,943
Depreciation and amortization	186,035	175,253	170,456
Taxes other than income taxes	41,728	40,949	38,869
Operating income	244,384	215,177	211,464
Other income (deductions)	4,165	(5,404)	4,016
Net interest deductions	66,957	68,777	75,113
Net interest deductions on subordinated debentures	—	—	1,912
Income before income taxes	181,592	140,996	138,455
Income tax expense	64,973	49,576	47,073
Contribution to consolidated net income	$ 116,619	$ 91,420	$ 91,382

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 *Pipe Replacement Tracking Mechanisms* 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, which principally includes returns on COLI policies (including recognized net death benefits) and non-utility expenses, 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 is complete.

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 3.875% Senior Notes in March 2012 to repay $200 million 7.625% Senior Notes that matured in May 2012, and by additional interest on variable-rate IDRBs.

2011 vs. 2010

The contribution to consolidated net income from natural gas operations was relatively unchanged between 2011 and 2010; however, operating income improved by $3.7 million between years. The increase in operating margin and reduced financing costs were offset by higher operating expenses and a decrease in other income.

Operating margin increased $14 million between 2011 and 2010. Differences in heating demand, caused primarily by weather variations, accounted for the $14 million increase as colder-than-normal temperatures were experienced in Arizona in 2011. Incremental margin from rate relief in California ($2 million) and new customers ($2 million) was offset by an adjustment recorded during the third quarter of 2011 related to a regulatory deferral mechanism.

Operations and maintenance expense increased $3.6 million, or 1%, between 2011 and 2010 primarily due to general cost increases, partially offset by favorable claims experience under Southwest's self-insured medical plan. The increase also included approximately $1 million of costs associated with restoring service to approximately 20,000 Arizona customers in early February 2011, following an outage due to extreme weather conditions. Cost containment efforts (including lower staffing levels) mitigated the increases.

Depreciation expense increased $4.8 million, or 3%, as a result of additional plant in service. Average gas plant in service for 2011 increased $151 million, or 3%, as compared to 2010. This was attributable to pipeline capacity reinforcement work, franchise requirements, scheduled and accelerated pipe replacement activities, and new business.

Taxes other than income taxes increased $2.1 million primarily due to higher property tax rates in Arizona.

Other income declined $9.4 million between 2011 and 2010. COLI-related income in 2011 (resulting from recognized death benefits net of decreases in cash surrender values) was $700,000, while 2010 included income of $9.8 million due to an increase in COLI cash surrender values and recognized net death benefits. COLI income in 2010 was especially high due to strong equity-market returns on investments underlying the policies.

Net financing costs decreased $8.2 million between 2011 and 2010 primarily due to the redemption of $100 million of subordinated debentures in March 2010, cost savings from debt refinancing, and reduced interest rates associated with variable-rate debt (including reductions relating to the interest tracking mechanism for 2003 and 2008 Series A IDRBs).

Income tax expense included $1.6 million of previously unrecognized tax benefits and related interest associated with the expiration of the statute of limitations with respect to a previously recorded uncertain tax position.

Outlook for 2013

Operating margin for 2013 is expected to be favorably influenced by customer growth similar to 2012, as well as incremental margin associated with the Nevada rate case decision and California attrition adjustment.

Operating expenses for 2013 compared to 2012 will continue to be impacted by inflation, general cost increases, and depreciation expense on plant additions. A reduction in depreciation rates in Nevada will mitigate the depreciation expense increase. Incremental costs, including a $6.4 million increase in pension expense ($5 million net) for 2013 and higher property and general taxes, are expected to result in an overall operating expense increase of approximately 3% to 4%.

Southwest anticipates approximately $5 million in interest savings on an annualized basis due to debt refinancings and redemptions. These savings relate to the March 2012 issuance of $250 million in 3.875% Senior Notes and the repayment of the $200 million of 7.625% debt that occurred in May 2012, as well as the August 2012 redemption of the $14.3 million 1999 5.95% Series C IDRBs. Also included are interest savings expected to be realized from the planned redemption of the $30 million 5.45% 2003 Series C and $15 million 5.80% 2003 Series E IDRBs in the first quarter of 2013.

Results of Construction Services

Year Ended December 31,	2012	2011	2010
(Thousands of dollars)			
Construction revenues	$606,050	$483,822	$318,464
Operating expenses:			
Construction expenses	541,523	423,703	277,804
Depreciation and amortization	37,387	25,216	20,007
Operating income	27,140	34,903	20,653
Other income (deductions)	246	(8)	(166)
Net interest deductions	1,063	825	564
Income before income taxes	26,323	34,070	19,923
Income tax expense	10,303	13,727	7,852
Net income	16,020	20,343	12,071
Net income (loss) attributable to noncontrolling interest	(692)	(524)	(424)
Contribution to consolidated net income attributable to NPL	$ 16,712	$ 20,867	$ 12,495

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 the 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. The construction revenues included NPL contracts with Southwest totaling $83.4 million in 2012 and $92.1 million in 2011. NPL accounts for the services provided to Southwest at contractual (market) prices at contract inception.

Construction expenses increased $118 million, or 28%, due to the increase in replacement construction work. See *Loss on NPL Contract* on page 5 for additional information. Depreciation expense increased $12.2 million between the current year and the prior year 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.

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, the impact of bonus depreciation legislation, and the regulatory environment (encouraging the natural gas industry to replace aging pipeline infrastructure) are having a positive influence on NPL's revenue growth.

During the past several years, NPL has focused its efforts on obtaining pipe replacement work under both blanket contracts and incremental bid projects. For 2012 and 2011, approximately 75% of revenues were from replacement work. 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 bid on pipe replacement projects throughout the country and has made structural and transitional changes to match the increased size and complexity of the business, including key management changes. Though it sustained a sizeable individual contract loss during 2012, it nonetheless experienced its second highest net income in its history.

2011 vs. 2010

Contribution to consolidated net income from construction services for 2011 increased $8.4 million compared to 2010.

Revenues increased $165 million in 2011, a 52% improvement, when compared to 2010 primarily due to increased replacement construction. The construction revenues included NPL contracts with Southwest totaling $92.1 million in 2011 and $61.3 million in 2010. NPL accounts for the services provided to Southwest at contractual (market) prices.

Construction expenses increased $146 million, or 53%, between 2010 and 2011 due primarily to costs associated with the increase in replacement construction work. Depreciation expense increased $5.2 million as a result of an increase in the construction equipment fleet. Interest expense increased $261,000 between 2010 and 2011 due to an increase in outstanding debt. Gains on sales of equipment were $3.3 million and $1.5 million in 2011 and 2010, respectively.

Outlook for 2013

Revenues are subject to the timing and amount of work awarded to NPL by its utility customers. While it is very early in this process, current expectations are for 2013 revenues to approximate 2012 levels. Construction expenses for 2013 are expected to be favorably impacted by elimination of the loss on the fixed-price contract, partially offset by reduced gains on sales of equipment and increased costs associated with the structural changes made to management and support functions, as well as general cost increases in labor and materials.

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.

Nevada General Rate Case. Southwest filed a general rate application with the PUCN in April 2012 to recover increased costs for operations in northern and southern Nevada. In addition, the filing reflected additional investments in infrastructure and included changes in depreciation, cost of service, and cost of capital. Southwest requested an increase in revenue of $1.5 million, or 1.41%, in northern Nevada and $25.4 million, or 6.15%, in southern Nevada. In the application, Southwest requested an overall rate of return of 8.45% on original cost rate base of $115 million for northern Nevada and an overall rate of return of 7.44% on original cost rate base of $821 million for southern Nevada, a return on common equity of 10.65%, and a capital structure utilizing 54% common equity. Southwest also 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 and steel pipe.

The PUCN reached a decision in this proceeding in the fourth quarter of 2012 with rates effective November 2012. The Decision provides 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 provides 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 is expected to increase annual operating income by $11.4 million.

The Company reviewed the Decision and identified certain items that it ultimately submitted to the PUCN for reconsideration. Notably, the PUCN employed alternative capital structures for northern and southern Nevada instead of the actual capital structure of the Company that was supported by all parties. A Petition for Reconsideration ("Petition") was filed with the PUCN after the PUCN issued its order in this proceeding, requesting reconsideration of the findings in the decision relating to the capital structure and other cost of service issues. Similarly, the PUCN Staff filed a Petition for Rehearing on the same alternative capital structure issue addressed in Southwest's Petition. In December 2012, a decision was received which granted Southwest's Petition on certain issues pertaining to the cost of service items, denied the Company's request related to the capital structure, but granted the PUCN Staff's requested Petition for Rehearing on the capital structure. The reconsideration of the cost of service issues required a modification of the final Order, however ultimately continued to deny cost recovery for these items. The hearing related to the capital structure was held in January 2013, and the parties to the proceeding presented evidence in support of their respective positions on what capital structure the PUCN should utilize in establishing rates. A final PUCN decision on the rehearing is expected in the first quarter of 2013.

As it relates to the proposed infrastructure replacement mechanism, the PUCN Decision indicated a separate rulemaking docket will 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 has already been convened. The scope of the rulemaking was recently expanded in order to consider additional forms of recovery mechanisms. The next steps in the proceeding include the filing of additional comments by interested parties, reply comments, and the convening of another workshop in the first quarter of 2013. The Company anticipates the PUCN will issue a decision in this rulemaking docket by the end of the third quarter of this year.

California Annual Attrition. As part of the 2009 rate decision by the 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 has triggered an automatic rate of return adjustment mechanism, which resulted in 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 is $1.1 million.

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 included a capital structure consisting of 43% debt and 57% common equity, 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 the Post-Test Year Ratemaking Mechanism, which allows for annual attrition increases. The application includes the addition of an Infrastructure Reliability and Replacement Adjustment Mechanism to facilitate and complement projects involving the enhancement and replacement of gas infrastructure, providing timely cost recovery for qualifying non-revenue producing capital expenditures. Hearings on the general rate case application are anticipated in the third quarter of 2013 with new rates proposed to be effective January 2014.

Arizona General Rate Case. In November 2010, Southwest filed a general rate application with the Arizona Corporation Commission (“ACC”) for its Arizona rate jurisdiction. The ACC authorized a general rate increase of $52.6 million effective January 2012 which included a return on common equity of 9.50%, a fair value rate of return of 6.92% and a capital structure consisted of 47.7% long-term debt and 52.3% common equity, with an embedded cost of debt of 8.34%. The ACC also approved a full revenue decoupling mechanism with a monthly weather adjuster. Management has not determined the timing of filing its next general rate case in Arizona; however, Southwest agreed in the settlement in the most recent Arizona general rate case filing to not file a general rate case in Arizona until April 30, 2016. If approval of the decoupling mechanism is rescinded by the ACC, the prohibition against the filing of general rate cases will be eliminated.

Pipe Replacement Tracking Mechanisms

Customer-Owned Yardline (“COYL”) Program. At December 31, 2011, there were approximately 100,000 customers in Arizona whose natural gas meters are set-off away from the customer’s home (e.g., near a backyard property line), as opposed to a more traditional configuration in which the meter is adjacent to the home. Under the COYL configuration, the customer owns, operates, and is responsible for maintaining the service line that runs from the meter to the home. As these lines age, they periodically develop low pressure leaks which result in immediate termination of natural gas service, and a subsequent need for the customer to repair or replace the COYL prior to service restoration. To address the cost normally borne by the customer to repair or replace the COYL, the Company received approval to implement a program (as part of its 2010 Arizona rate case decision) under which the Company will replace the customer’s facilities at no immediate direct cost to the customer, and relocate the customer’s meter adjacent to the home, thereby eliminating the customer’s previous operating and maintenance responsibilities associated with the COYL. In addition, the program provides for the Company to endeavor to leak survey all such COYLs over a 3-year period; anticipated costs for the survey are reflected in current rates. As of December 31, 2012, approximately 50,000 COYL services had been inspected and 2,000 relocated. The costs of the replacement portion of this program are capitalized by the Company and were approximately $4 million in 2012. Subject to an annual reporting requirement, a surcharge is added to all bills to recover an amount approximately equal to the amount that the Company would have earned if the additional pipe replacement costs had been included in the rate base amount filed in the 2010 Arizona rate case. Recovery of the surcharge will cease as of the next Arizona general rate case (as the expenditures will then be included in rate base).

Nevada Pipe Replacement Program. The Company identified specific pipe replacement projects (including early vintage plastic pipe) for accelerated replacement in its Northern Nevada jurisdiction during 2011 and for its Southern Nevada jurisdiction during 2011 and 2012. The PUCN authorized Southwest to accumulate the incremental depreciation and carrying costs associated with these projects as a regulatory asset through January 2015, by which time any accumulated costs must be reflected in rates pursuant to a general rate case filing, or become subject to an eight-year amortization period; recovery of unamortized post-2015 balances may also be requested in a general rate case filing. As part of the Decision reached in the 2012 general rate case, Southwest was authorized to recover costs accumulated through May 2012 over an eight-year period and to continue to defer the incremental depreciation and carrying costs for approved projects, which will be included in a future general rate case proceeding.

FERC Jurisdiction. In February 2009, Paiute Pipeline Company, a wholly owned subsidiary of the Company, filed its most recent general rate case with the Federal Energy Regulatory Commission ("FERC"). In April 2010, the FERC approved an offer of settlement from Paiute which resolved all issues related to its general rate case. The settlement provided for an increase of approximately $900,000 in Paiute's annual operating income and was effective September 2009. Management has not determined the timing of filing its next general rate case with the FERC; however, in the settlement, Paiute agreed to file its next general rate case on or by February 28, 2014.

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, 2012, over-collections in Arizona and Nevada resulted in a liability of $98.9 million and under-collections in California resulted in an asset of $6 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):

	2012	2011
Arizona	$(46.6)	$(28.4)
Northern Nevada	(7.1)	(7.9)
Southern Nevada	(45.2)	(36.1)
California	6.0	2.3
	$(92.9)	$(70.1)

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. During 2012, approximately $40 million was refunded to customers via the surcredit; however, continued low natural gas prices resulted in a continuing balance due 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. 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 2012, 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 2013. Southwest makes quarterly DEAA adjustments based upon a twelve-month rolling average. During 2012, approximately $53 million was refunded to customers via billing credits; however, base tariff rates continued to exceed average rates paid for natural gas in 2012 resulting in a net increase in the balance payable to customers.

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 fixed-for-floating swap contracts ("Swaps") under its collective volatility mitigation programs for a portion (currently ranging from 25% to 35%, depending on the jurisdiction) of its annual normal weather supply needs. For the 2012/2013 heating season, contracts contained in the fixed-price portion of the portfolio range in price from approximately $3 to $5 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.

Capital Resources and Liquidity

Cash on hand and cash flows from operations have generally been sufficient over the past three years to provide for net investing activities (primarily construction expenditures and property additions). Certain pipe replacement work was accelerated during 2011 and 2012 to take advantage of bonus depreciation tax incentives. 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 increased $134 million in 2012 as compared to 2011. The improvement in operating cash flows was attributable to greater net income and non-cash depreciation expense and temporary net cash flow increases resulting from changes in working capital components.

Investing Cash Flows. Cash used in consolidated investing activities increased $15.2 million in 2012 as compared to 2011. The increase was primarily due to additional construction expenditures, including scheduled and accelerated pipe replacement, and equipment purchases by NPL due to the increased replacement construction work of its customers.

Financing Cash Flows. Net cash used in consolidated financing activities increased $21.3 million in 2012 as compared to 2011. A forward-starting interest rate swap ("FSIRS") contract was settled by paying $21.8 million during the first quarter of 2012 (at maturity). See Note 13 – Derivatives and Fair Value Measurements for more information regarding the FSIRS. Dividends paid increased in 2012 as compared to 2011 as a result of an increase in the quarterly dividend and an increase in the number of shares

outstanding. The issuance of new debt including the $250 million 3.875% Senior Notes and borrowings on the long-term portion of the credit facility was partially offset by debt repayments including 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 (originally due in 2038) repaid in August 2012. The remaining issuance amounts and retirements of long-term debt primarily relate to borrowings and repayments under NPL's line of credit. The prior year included the repayment of the $200 million 8.375% Notes and the issuance of the $125 million 6.1% Notes.

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.

2012 Construction Expenditures

During the three-year period ended December 31, 2012, total gas plant increased from $4.4 billion to $5 billion, or at an average annual rate of 4%. 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 47,000 meters during the three-year period.

During 2012, construction expenditures for the natural gas operations segment were $309 million. The majority of these expenditures represented costs associated with scheduled and accelerated replacement of existing transmission, distribution, and general plant (see also *Bonus Depreciation* below). Cash flows from operating activities of Southwest were $344 million and provided approximately 95% 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 existing credit facilities.

2012 Financing Activity

In January 2012, the Company redeemed at par its $12.4 million 1999 6.1% Series A fixed-rate IDRBs. The IDRBs were originally due in 2038. In February 2012, the Company drew down the remaining $12.8 million in restricted cash from a 2009 IDRB offering. In March 2012, the Company issued $250 million in 3.875% Senior Notes. The notes will mature on April 1, 2022. Management used approximately $200 million of the net proceeds in connection with the repayment of the $200 million 7.625% Senior Notes that matured in May 2012. The remaining net proceeds were used for general corporate purposes. In August 2012, the Company redeemed at par its $14.3 million 1999 5.95% Series C fixed-rate IDRBs (originally due in 2038). During 2012, the Company issued shares of common stock through its various stock plans, including the Stock Incentive Plan, raising approximately $2 million.

Bonus Depreciation. In September 2010, the Small Business Jobs Act of 2010 ("Act") was signed into law. The Act provided a 50% bonus tax depreciation deduction for qualified property acquired or constructed and placed in service in 2010. In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 ("Tax Relief Act") was signed into law. The Tax Relief Act provided for a temporary 100% bonus tax depreciation deduction for qualified property acquired or constructed and placed in service after September 8, 2010 and before January 1, 2012 and extended the availability of the 50% bonus tax depreciation deduction through December 31, 2012. In January 2013, the American Taxpayer Relief Act of 2012 ("Taxpayer Relief Act") was enacted extending the 50% bonus tax depreciation deduction for qualified property acquired or constructed and placed in-service during 2013. Based on forecasted qualifying construction expenditures, Southwest estimates the bonus depreciation provisions of the two acts will defer the payment of approximately $30 million and $37 million of federal income taxes for 2012 and 2013, respectively.

Three-Year Construction Expenditures, Debt Maturities, and Financing

Southwest estimates natural gas segment construction expenditures during the three-year period ending December 31, 2015 will be approximately $1 billion. Of this amount, approximately $320 million to $360 million are expected to be incurred in 2013 depending on the approval and timing of requested infrastructure replacement mechanisms in Nevada (see **Rates and Regulatory Proceedings**). Southwest has taken advantage of bonus depreciation tax benefits 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. During the three-year period, cash flows from operating activities of Southwest (including the bonus depreciation benefits) 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 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.

The Company's $30 million 2003 5.45% Series C fixed-rate IDRBs and $15 million 2003 5.8% Series E fixed-rate IDRBs include a put feature that requires the remarketing of these IDRBs on March 1, 2013. The Company has the option to remarket these IDRBs at various intervals until the due date of 2038. However, once the remarketing process in March 2013 is complete, the Company intends to redeem these IDRB's at par. These IDRBs are shown as current maturities in the Company's consolidated balance sheet. The Company will facilitate the redemption primarily from borrowings under its $300 million credit facility.

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. At December 31, 2012, the combined balance in the PGA accounts totaled an over-collection of $92.9 million. See **PGA Filings** for more information.

In March 2012, the Company replaced a $300 million revolving credit facility that was to expire in May 2012 with a $300 million facility that is scheduled to expire 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 the Company's current unsecured debt rating, the applicable margin is 1.125% for loans bearing interest with reference to LIBOR and 0.125% 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. The borrowings at December 31, 2011 (and additional borrowings which resulted in a maximum outstanding balance of $128 million during the first quarter) under the predecessor facility were repaid during the first quarter of 2012. At December 31, 2012, $111 million was outstanding on the long-term portion of the new credit facility (including $20 million under the commercial paper program), and no borrowings were outstanding on the short-term portion. No borrowings occurred under the new facility during the second quarter of 2012, and the maximum amount outstanding during the third and fourth quarters of 2012 was $40 million and $130 million, respectively. The credit facility can be used as necessary to meet liquidity requirements, including temporarily financing under-collected PGA balances, if any, or meeting the refund needs of over-collected balances. 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, 2012, $20 million was outstanding on the commercial paper program. The maximum amount outstanding during the year was $20 million.

In June 2012, NPL replaced its existing $30 million revolving credit facility that was to expire in June 2013 with a $75 million facility that is scheduled to expire in June 2015. The credit facility was amended in October 2012 to temporarily increase the facility from $75 million to $85 million until December 29, 2012 and then reverted back to $75 million. Interest rates for the credit facility were also amended in October 2012 and are now 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, 2012, $41.6 million was 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 2012, Moody's upgraded the Company's senior unsecured long-term debt rating to Baa1 from Baa2 (the outlook remains stable). Moody's cited the Company's prospects for continued strong financial results and credit metrics, as well as the resolution of the Arizona rate case as factors in its decision. Moody's applies a Baa rating to obligations which are considered medium grade obligations with adequate security. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the Baa to indicate the approximate rank of a company within the range.

In May 2012, Fitch upgraded the Company's senior unsecured long-term debt rating to A- from BBB+ (the outlook has been revised to positive from stable). Fitch cited the Company's strong operational performance for 2011 and expectations for continued strong performance for 2012, due in part to the recent rate design changes adopted in Arizona. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of A- indicates low credit risk and a strong ability to pay financial commitments.

The Company's unsecured long-term debt rating from Standard & Poor's Ratings Services ("S&P") is BBB+ with a stable outlook as of April 2011. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of BBB+ indicates the issuer of the debt is regarded as having an adequate capacity to pay interest and repay principal.

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. Certain debt instruments also have leverage ratio caps and minimum net worth requirements. At December 31, 2012, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.7 billion in additional debt and meet the leverage ratio requirement. The Company has at least $700 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, 2012 (millions of dollars):

	Payments due by period				
Contractual Obligations	Total	2013	2014-2015	2016-2017	Thereafter
Operating activities:					
Operating leases (Note 2)	$ 18	$ 7	$ 7	$ 4	$ —
Gas purchase obligations	165	117	48	—	—
Pipeline capacity	793	110	194	123	366
Derivatives (Note 13)	3	2	1	—	—
Other commitments	15	7	7	1	—
Financing activities:					
Long-term debt, including current maturities (Note 7)	1,319	50	52	141	1,076
Interest on long-term debt	843	52	102	99	590
Other	16	—	1	2	13
Total	$3,172	$345	$412	$370	$2,045

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 147 million dekatherms. Fixed-price contracts range in price from approximately $3 to $5 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

Southwest has pipeline capacity 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.

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. Southwest's plans to redeem $45 million of IDRBs in March 2013 (originally due in 2038) are also reflected in the table above. See Capital Resources and Liquidity.

Other: Estimated funding for pension and other postretirement benefits during calendar year 2013 is $47 million.

Recently Issued Accounting Standards Updates

The Financial Accounting Standards Board ("FASB") recently issued Accounting Standards Updates related to offsetting of assets and liabilities on the balance sheets, testing of indefinite-lived intangible

assets for impairment, and technical corrections and improvements. See **Note 1 – Summary of Significant Accounting Policies** for more information regarding these accounting standards updates and their potential impact on the Company's financial position, results of operations, and disclosures.

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 $31.4 million and future pension expense by $3.3 million. A change of 0.25% in the employee compensation assumption would change the pension obligation by approximately $7.8 million and expense by $1.6 million. A 0.25% change in the expected asset return assumption would change pension expense by approximately $1.5 million (but has no impact on the pension obligation).

At December 31, 2012, the Company lowered the discount rate to 4.25% from a rate of 5.00% at December 31, 2011. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase decreased to 2.75% at December 31, 2012 from 3.00% in the prior year. The asset return assumption remains the same at 8.00%. The significant reduction in the discount rate will increase the expense level for 2013. Pension expense for 2013 is estimated to increase by $6.4 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.

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, 2012 are included as exhibits to the 2012 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," 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, use of proceeds, 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, forecasted operating cash flows and results of operations, incremental operating margin in 2013, operating expense increases in 2013, funding sources of cash requirements, sufficiency of working capital, 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, NPL's bid contracts (or contracts with caps) and results thereunder, including expectations regarding estimates of costs and revenues, pension and post-retirement benefits, certain benefits of tax acts, the effect of rate decoupling in Arizona, the effect of any rate changes or regulatory proceedings, including the Decision from the PUCN and the California general rate case filing, statements regarding future gas prices, gas purchase contracts and derivative financial instruments, 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, 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, acquisitions and management's plans related thereto, 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, 2012.

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

	2012		2011		Dividends Declared	
	High	Low	High	Low	2012	2011
First quarter	$43.64	$40.51	$39.68	$36.33	$0.295	$0.265
Second quarter	44.64	39.46	40.59	36.61	0.295	0.265
Third quarter	46.08	42.19	39.92	32.12	0.295	0.265
Fourth quarter	44.83	39.01	43.20	34.55	0.295	0.265
					$1.180	$1.060

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 15, 2013, there were 15,969 holders of record of common stock, and the market price of the common stock was $44.50.

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 25 cents per share throughout 2010, 26.5 cents per share throughout 2011, and 29.5 cents per share throughout 2012. As a result of its ongoing review of dividend policy, in February 2013, the Board increased the quarterly dividend from 29.5 cents to 33 cents per share, effective with the June 2013 payment. This marks the seventh 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
CONSOLIDATED BALANCE SHEETS
(Thousands of dollars, except par value)

December 31,	2012	2011
ASSETS		
Utility plant:		
Gas plant	$ 5,019,500	$ 4,811,050
Less: accumulated depreciation	(1,750,795)	(1,638,091)
Acquisition adjustments, net	911	1,091
Construction work in progress	74,178	44,894
Net utility plant (Note 2)	3,343,794	3,218,944
Other property and investments	242,096	192,004
Restricted cash	—	12,785
Current assets:		
Cash and cash equivalents	25,530	21,937
Accounts receivable, net of allowances (Note 3)	196,913	209,246
Accrued utility revenue	72,000	70,300
Income taxes receivable, net	2,945	7,793
Deferred income taxes (Note 12)	47,088	53,435
Deferred purchased gas costs (Note 4)	6,031	2,323
Prepaids and other current assets (Notes 1 and 4)	107,910	96,598
Total current assets	458,417	461,632
Deferred charges and other assets (Notes 4 and 13)	443,750	390,642
Total assets	$ 4,488,057	$ 4,276,007

CONSOLIDATED BALANCE SHEETS - Continued

December 31,	2012	2011
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized – 60,000,000 shares; issued and outstanding – 46,147,788 and 45,956,088 shares) (Note 11)	$ 47,778	$ 47,586
Additional paid-in capital	828,777	821,640
Accumulated other comprehensive income (loss), net (Note 5)	(50,745)	(49,331)
Retained earnings	484,369	406,125
Total Southwest Gas Corporation equity	1,310,179	1,226,020
Noncontrolling interest	(1,681)	(989)
Total equity	1,308,498	1,225,031
Long-term debt, less current maturities (Note 7)	1,268,373	930,858
Total capitalization	2,576,871	2,155,889
Commitments and contingencies (Note 9)		
Current liabilities:		
Current maturities of long-term debt (Note 7)	50,137	322,618
Accounts payable	155,667	186,755
Customer deposits	77,858	83,839
Accrued general taxes	37,644	42,102
Accrued interest	16,080	16,699
Deferred purchased gas costs (Note 4)	98,957	72,426
Other current liabilities (Notes 4 and 13)	98,786	123,129
Total current liabilities	535,129	847,568
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 12)	616,184	557,118
Taxes payable	551	828
Accumulated removal costs (Note 4)	256,000	233,000
Other deferred credits (Notes 4 and 10)	503,322	481,604
Total deferred income taxes and other credits	1,376,057	1,272,550
Total capitalization and liabilities	$4,488,057	$4,276,007

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share amounts)

Year Ended December 31,	2012	2011	2010
Operating revenues:			
Gas operating revenues	$1,321,728	$1,403,366	$1,511,907
Construction revenues	606,050	483,822	318,464
Total operating revenues	1,927,778	1,887,188	1,830,371
Operating expenses:			
Net cost of gas sold	479,602	613,489	736,175
Operations and maintenance	369,979	358,498	354,943
Depreciation and amortization	223,422	200,469	190,463
Taxes other than income taxes	41,728	40,949	38,869
Construction expenses	541,523	423,703	277,804
Total operating expenses	1,656,254	1,637,108	1,598,254
Operating income	271,524	250,080	232,117
Other income and (expenses):			
Net interest deductions (Notes 7 and 8)	(68,020)	(69,602)	(75,677)
Net interest deductions on subordinated debentures (Note 6)	—	—	(1,912)
Other income (deductions)	4,411	(5,412)	3,850
Total other income and (expenses)	(63,609)	(75,014)	(73,739)
Income before income taxes	207,915	175,066	158,378
Income tax expense (Note 12)	75,276	63,303	54,925
Net income	132,639	111,763	103,453
Net income (loss) attributable to noncontrolling interest	(692)	(524)	(424)
Net income attributable to Southwest Gas Corporation	$ 133,331	$ 112,287	$ 103,877
Basic earnings per share (Note 15)	$ 2.89	$ 2.45	$ 2.29
Diluted earnings per share (Note 15)	$ 2.86	$ 2.43	$ 2.27
Average number of common shares outstanding	46,115	45,858	45,405
Average shares outstanding (assuming dilution)	46,555	46,291	45,823

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of dollars)

Year Ended December 31,	2012	2011	2010
Net Income	$132,639	$111,763	$103,453
Other comprehensive income (loss), net of tax			
Defined benefit pension plans (Notes 5 and 10):			
Net actuarial gain (loss)	(46,409)	(84,005)	(5,616)
Amortization of transition obligation	538	537	538
Amortization of net actuarial loss	15,870	9,653	7,516
Prior service cost	(1,502)	—	—
Regulatory adjustment	26,518	65,677	404
Net defined benefit pension plans	(4,985)	(8,138)	2,842
Forward-starting interest rate swaps:			
Unrealized/realized gain (loss) (Notes 5 and 13)	1,834	(11,134)	(11,436)
Amounts reclassified into net income (Notes 5 and 13)	1,737	725	60
Net forward-starting interest rate swaps	3,571	(10,409)	(11,376)
Total other comprehensive income (loss), net of tax	(1,414)	(18,547)	(8,534)
Comprehensive income	131,225	93,216	94,919
Comprehensive income (loss) attributable to noncontrolling interest	(692)	(524)	(424)
Comprehensive income attributable to Southwest Gas Corporation	$131,917	$ 93,740	$ 95,343

The accompanying notes are an integral part of these statements.

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

Year Ended December 31,	2012	2011	2010
CASH FLOW FROM OPERATING ACTIVITIES:			
Net Income	$132,639	$111,763	$103,453
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	223,422	200,469	190,463
Deferred income taxes	66,280	56,467	50,111
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	12,333	(61,641)	10,117
Accrued utility revenue	(1,700)	(5,900)	7,300
Deferred purchased gas costs	22,823	(52,885)	33,013
Accounts payable	(25,998)	15,826	6,680
Accrued taxes	113	14,979	(15,240)
Other current assets and liabilities	(18,948)	(3,347)	12,895
Gains on sale	(8,040)	(3,307)	(1,547)
Changes in undistributed stock compensation	5,137	6,125	4,429
AFUDC and property-related changes	(1,943)	(1,154)	(945)
Changes in other assets and deferred charges	(15,367)	11,025	(12,262)
Changes in other liabilities and deferred credits	(4,427)	(36,378)	(17,474)
Net cash provided by operating activities	386,324	252,042	370,993

CONSOLIDATED STATEMENTS OF CASH FLOWS - Continued

Year Ended December 31,	2012	2011	2010
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(395,712)	(380,991)	(215,439)
Restricted cash	12,785	24,996	11,988
Changes in customer advances	(3,025)	(7,771)	(830)
Miscellaneous inflows	13,963	7,686	4,075
Miscellaneous outflows	(2,004)	(2,719)	(2,800)
Net cash used in investing activities	(373,993)	(358,799)	(203,006)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	1,581	7,402	11,098
Dividends paid	(53,040)	(47,929)	(44,846)
Interest rate swap settlement	(21,754)	—	(11,691)
Issuance of long-term debt, net	489,518	274,598	123,960
Retirement of long-term debt	(427,043)	(330,473)	(3,327)
Redemption of subordinated debentures	—	—	(100,000)
Change in credit facility and commercial paper	2,000	109,000	(92,400)
Net cash provided by (used in) financing activities	(8,738)	12,598	(117,206)
Change in cash and cash equivalents	3,593	(94,159)	50,781
Cash and cash equivalents at beginning of period	21,937	116,096	65,315
Cash and cash equivalents at end of period	$ 25,530	$ 21,937	$ 116,096
Supplemental information:			
Interest paid, net of amounts capitalized	$ 87,439	$ 69,842	$ 87,000
Income taxes paid (received)	$ 2,843	$ (13,635)	$ 19,200

The accompanying notes are an integral part of these statements.

SOUTHWEST GAS CORPORATION
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, 2009	45,092	$46,722	$792,339	$(22,250)	$285,316	$ (41)	$1,102,086
Common stock issuances	507	507	15,546				16,053
Net income (loss)					103,877	(424)	103,453
Net actuarial gain (loss) arising during the period, less amortization of unamortized benefit plan cost, net of tax (Notes 5 and 10)				2,842			2,842
FSIRS realized and unrealized loss, net of tax (Notes 5 and 13)				(11,436)			(11,436)
Amounts reclassified to net income, net of tax (Notes 5 and 13)				60			60
Dividends declared Common: $1.00 per share					(46,062)		(46,062)
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 10)				(8,138)			(8,138)
FSIRS realized and unrealized loss, net of tax (Notes 5 and 13)				(11,134)			(11,134)
Amounts reclassified to net income, net of tax (Notes 5 and 13)				725			725
Dividends declared Common: $1.06 per share					(49,293)		(49,293)

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, 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 10)				(4,985)			(4,985)
FSIRS realized and unrealized gain, net of tax (Notes 5 and 13)				1,834			1,834
Amounts reclassified to net income, net of tax (Notes 5 and 13)				1,737			1,737
Dividends declared Common: $1.18 per share					(55,087)		(55,087)
DECEMBER 31, 2012	46,148*	$47,778	$828,777	$(50,745)	$484,369	$(1,681)	$1,308,498

* At December 31, 2012, 2.2 million common shares were registered and available for issuance under provisions of the Company's various stock issuance plans. In addition, approximately 125,000 common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 11).

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. In November 2009, NPL entered into a venture to market natural gas engine-driven heating, ventilating, and air conditioning ("HVAC") technology and products. NPL has a 65% interest in the entity (IntelliChoice Energy, "ICE") and consolidates ICE 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):

	2012	2011
NPL property and equipment	$ 287	$ 237
Accumulated provision for depreciation and amortization	(136)	(128)
Net cash surrender value of COLI policies	80	74
Other property	11	9
Total	$ 242	$ 192

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 plant materials and operating supplies of $25 million in 2012 and $21 million in 2011.

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, approximately $20 million of customer advances, upon contract expiration, were applied as contributions offsetting construction expenditures as 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, 2012	December 31, 2011
Accumulated removal costs	$256,000	$233,000

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 the 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 reflect pretax losses (with after-tax earnings per share impacts) of $15 million ($0.20 per share) for the year ended December 31, 2012, including $18 million ($0.24 per share) in the first half of 2012. The estimated cost changes that resulted in the losses recognized included reductions in projected productivity and higher costs of restoration work. Change orders approved during the fourth quarter of 2012 helped to reduce losses overall on the contract. On a contract-to-date basis the cumulative loss is $10 million. At December 31, 2012, work on this sizeable contract is over 95% 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.

(In thousands)	2012	2011	2010
AFUDC:			
Debt portion	$1,129	$ 718	$ 512
Equity portion	1,943	1,154	945
AFUDC capitalized as part of utility plant	$3,072	$1,872	$1,457

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):

	2012	2011	2010
Change in COLI policies	$ 6,600	$ 700	$ 9,770
Interest income	924	485	194
Pipe replacement costs	(2,680)	(4,761)	(5,024)
Miscellaneous income and (expense)	(433)	(1,836)	(1,090)
Total other income (deductions)	$ 4,411	$(5,412)	$ 3,850

Included in the table above is the change in cash surrender values of company-owned life insurance (“COLI”) policies (including net death benefits recognized). 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, the change in the cash surrender value components of COLI policies, as they progress towards the ultimate death benefits, is 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 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.

(In thousands)	2012	2011	2010
Average basic shares	46,115	45,858	45,405
Effect of dilutive securities:			
Stock options	42	52	56
Performance shares	254	271	260
Restricted stock units	144	110	102
Average diluted shares	46,555	46,291	45,823

Recently Issued Accounting Standards Updates. In October 2012, the Financial Accounting Standards Board ("FASB") issued the update "Technical Corrections and Improvements" which clarifies or corrects unintended application of accounting guidance. Many of these changes are not expected to have a significant effect on current accounting practice but some improvements are more substantive and are not technical corrections. Amendments included in the update without transition guidance were effective upon issuance. Amendments subject to transition guidance were effective for the Company on January 1, 2013 for interim and annual reporting periods. The adoption of the update is not expected to have a material impact on the Company's disclosures, financial position, or results of operations.

In July 2012, the FASB issued the update "Intangibles – Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment," which provides that an entity has the option to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not that an indefinite-lived intangible asset is impaired. If, in electing the qualitative evaluation step, there is no indication of impairment, quantitative impairment testing would not be required to be performed. The update would provide consistency in evaluation for goodwill and indefinite-lived intangibles other than goodwill. The Company adopted this update, as required, on January 1, 2013. The adoption of the update is not expected to have a material impact on the financial position or results of operations of the Company.

In December 2011, the FASB issued the update "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." The update requires an entity to disclose information about financial instruments and derivative instruments that are either offset or subject to an enforceable master netting arrangement or similar agreement. This information is intended to enable users of an entity's financial statements to understand the effect of those arrangements on the entity's financial position. In January 2013, the FASB issued the update "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities" ("Clarification") that clarifies the scope of the "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" update. The amendments included in the Clarification apply to entities that have derivatives, repurchase agreements and reverse repurchase agreements, and certain securities borrowing and securities lending transactions that are offset, or subject to a master netting or similar agreement. Entities with other types of financial assets and financial liabilities subject to a master netting or similar agreements would no longer be subject to the disclosure requirements in the initial update. All disclosures are required to be provided retrospectively for all periods presented. The Company adopted both updates, as required, on January 1, 2013 for interim and annual reporting periods. These updates are not expected to have a material impact on the Company's disclosures.

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, 2012 and 2011 was as follows (thousands of dollars):

December 31,	2012	2011
Gas plant:		
Storage	$ 20,503	$ 20,496
Transmission	301,505	295,103
Distribution	4,224,560	4,048,078
General	310,936	291,639
Other	161,996	155,734
	5,019,500	4,811,050
Less: accumulated depreciation	(1,750,795)	(1,638,091)
Acquisition adjustments, net	911	1,091
Construction work in progress	74,178	44,894
Net utility plant	$ 3,343,794	$ 3,218,944

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

	2012	2011	2010
Depreciation and amortization expense	$182,612	$172,712	$167,050

Operating Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas and its administrative offices in Phoenix. The table below presents the rental payments and the current term expiration dates, although both leases have optional renewal terms available.

(In thousands)	2013	2014	2015	2016	2017
Corporate headquarters (expires in 2017)	$2,140	$2,190	$ 2,270	$ 2,343	$ 1,194
Phoenix administrative offices (expires in 2014)	1,446	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 for all operating leases (in thousands):

	2012	2011	2010
Southwest Gas	$ 7,762	$ 7,812	$ 7,585
NPL	24,054	19,017	11,780
Consolidated rental payments/lease expense	$31,816	$26,829	$19,365

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, 2012 (thousands of dollars):

Year Ending December 31,	
2013	$ 6,757
2014	4,304
2015	3,181
2016	2,510
2017	1,238
Thereafter	61
Total minimum lease payments	$18,051

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 at December 31, 2012, and the percentage of customers in each of the three states.

Gas utility customer accounts receivable balance (in thousands)	$	94,695

	December 31, 2012
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, 2009	$ 3,953
Additions charged to expense	2,646
Accounts written off, less recoveries	(3,405)
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

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”). Southwest accounting policies 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,	2012	2011
Regulatory assets:		
Accrued pension and other postretirement benefit costs (1)	$ 373,615	$ 330,844
Unrealized net loss on non-trading derivatives (Swaps) (2)	2,395	11,743
Deferred purchased gas costs (3)	6,031	2,323
Accrued purchased gas costs (4)	30,300	18,400
Unamortized premium on reacquired debt (5)	19,452	19,011
Other (6)	44,927	32,988
	476,720	415,309
Regulatory liabilities:		
Deferred purchased gas costs (3)	(98,957)	(72,426)
Accumulated removal costs	(256,000)	(233,000)
Unrealized net gain on non-trading derivatives (Swaps) (2)	(6)	—
Deferred gain on southern Nevada division operations facility (7)	(392)	(806)
Unamortized gain on reacquired debt (8)	(11,934)	(12,470)
Other (9)	(6,951)	(14,501)
Net regulatory assets	$ 102,480	$ 82,106

(1) Included in Deferred charges and other assets on the Consolidated Balance Sheets. Recovery period is greater than five years. (See Note 10).

(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 13).

Instrument	Balance Sheet Location	2012	2011
Swaps	Deferred charges and other assets	$ 319	$ 621
Swaps	Prepaids and other current assets	2,076	11,122
Swaps	Other deferred credits	(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 and recovered over one year or less.

(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 Decision, 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)

	2012			2011			2010		
	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)	$(74,853)	$ 28,444	$(46,409)	$(135,492)	$ 51,487	$(84,005)	$ (9,058)	$ 3,442	$ (5,616)
Amortization of transition obligation	867	(329)	538	867	(330)	537	867	(329)	538
Amortization of net actuarial (gain)/loss	25,597	(9,727)	15,870	15,569	(5,916)	9,653	12,122	(4,606)	7,516
Prior service cost	(2,423)	921	(1,502)	—	—	—	—	—	—
Regulatory adjustment	42,771	(16,253)	26,518	105,931	(40,254)	65,677	652	(248)	404
Pension plans other comprehensive income (loss)	(8,041)	3,056	(4,985)	(13,125)	4,987	(8,138)	4,583	(1,741)	2,842
FSIRS (designated hedging activities):									
Unrealized/realized gain (loss)	2,959	(1,125)	1,834	(17,958)	6,824	(11,134)	(18,446)	7,010	(11,436)
Amounts reclassified into net income	2,801	(1,064)	1,737	1,169	(444)	725	97	(37)	60
FSIRS other comprehensive income (loss)	5,760	(2,189)	3,571	(16,789)	6,380	(10,409)	(18,349)	6,973	(11,376)
Total other comprehensive income (loss)	$ (2,281)	$ 867	$ (1,414)	$ (29,914)	$ 11,367	$(18,547)	$(13,766)	$ 5,232	$ (8,534)

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

Approximately $2.1 million of realized losses (net of tax) related to the forward-starting interest rate swaps (“FSIRS”), reported in AOCI at December 31, 2012, will be reclassified into expense within the next twelve months as the related interest payments on long-term debt occur.

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	$ 32,400
SERP net actuarial loss	1,000
PBOP net actuarial loss	1,000
PBOP prior service cost	400

The following 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 10)			FSIRS (Note 13)			
	Before-Tax	Tax (Expense) Benefit	After-Tax	Before-Tax	Tax (Expense) Benefit	After-Tax	AOCI
Beginning Balance AOCI December 31, 2011	$(44,429)	$16,883	$(27,546)	$(35,138)	$13,353	$(21,785)	$(49,331)
Current period other comprehensive income (loss)	(8,041)	3,056	(4,985)	5,760	(2,189)	3,571	(1,414)
Ending Balance AOCI December 31, 2012	$(52,470)	$19,939	$(32,531)	$(29,378)	$11,164	$(18,214)	$(50,745)

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, 2012 and 2011:

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

	2012	2011
Net actuarial (loss) gain	$(423,662)	$(374,406)
Prior service cost	(2,423)	—
Net transition obligation	—	(867)
Less: amount recognized in regulatory assets	373,615	330,844
Recognized in AOCI	$ (52,470)	$ (44,429)

See Note 10 – Pension and Other Postretirement Benefits for more information on the defined benefit pension plans and Note 13 – Derivatives and Fair Value Measurements for more information on the FSIRS.

Note 6 – Preferred Trust Securities and Subordinated Debentures

In June 2003, the Company created Southwest Gas Capital II ("Trust II"), a wholly owned subsidiary, as a financing trust for the sole purpose of issuing preferred trust securities for the benefit of the Company. In

August 2003, Trust II publicly issued $100 million of 7.70% Preferred Trust Securities ("Preferred Trust Securities"). In connection with the Trust II issuance of the Preferred Trust Securities and the related purchase by the Company for $3.1 million of all of the Trust II common securities ("Common Securities"), the Company issued $103.1 million principal amount of its 7.70% Junior Subordinated Debentures ("Subordinated Debentures") to Trust II. The Subordinated Debentures became redeemable at the option of the Company in August 2008.

In February 2010, the Company notified holders of the Subordinated Debentures that all of these debentures (and the associated preferred and common securities) would be redeemed (at par) by the Company in March 2010. All of the outstanding Subordinated Debentures were redeemed in March 2010. The Company accomplished the redemption using existing cash and borrowings under the previous $300 million credit facility.

Interest payments and amortizations associated with the Subordinated Debentures are classified on the 2010 consolidated statement of income as Net interest deductions on subordinated debentures.

Note 7 – Long-Term Debt

Carrying amounts of the Company's long-term debt and their related estimated fair values as of December 31, 2012 and December 31, 2011 are disclosed in the following table. The fair values of the revolving credit facility, 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 4.45% Notes) and fixed-rate IDRBs are categorized as Level 2. The 4.45% Notes and NPL other debt obligations 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,	2012		2011	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
Notes, 7.625%, due 2012	$ —	$ —	$200,000	$204,312
Notes, 4.45%, due 2020	125,000	141,771	125,000	128,673
Notes, 6.1%, due 2041	125,000	165,779	125,000	143,074
Notes, 3.875%, due 2022	250,000	277,950	—	—
8% Series, due 2026	75,000	111,501	75,000	96,340
Medium-term notes, 7.59% series, due 2017	25,000	30,710	25,000	30,199
Medium-term notes, 7.78% series, due 2022	25,000	34,637	25,000	31,932
Medium-term notes, 7.92% series, due 2027	25,000	36,953	25,000	31,648
Medium-term notes, 6.76% series, due 2027	7,500	10,058	7,500	8,510
Unamortized discount	(3,403)		(2,087)	
	654,097		605,413	
Revolving credit facility and commercial paper	111,000	111,000	109,000	109,000

December 31,	2012		2011	
	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:				
6.10% 1999 Series A, due 2038	—	—	12,410	12,410
5.95% 1999 Series C, due 2038	—	—	14,320	14,449
5.55% 1999 Series D, due 2038	8,270	8,375	8,270	8,253
5.45% 2003 Series C, due 2038 (rate resets in March 2013)	30,000	30,152	30,000	31,332
5.25% 2003 Series D, due 2038	20,000	20,571	20,000	19,583
5.80% 2003 Series E, due 2038 (rate resets in March 2013)	15,000	15,102	15,000	15,634
5.25% 2004 Series A, due 2034	65,000	66,955	65,000	64,291
5.00% 2004 Series B, due 2033	31,200	31,655	31,200	30,283
4.85% 2005 Series A, due 2035	100,000	101,184	100,000	94,836
4.75% 2006 Series A, due 2036	24,855	25,189	24,855	23,179
Unamortized discount	(3,195)		(3,360)	
	491,130		517,695	
NPL credit facility	41,562	41,562	16,566	16,566
NPL other debt obligations	20,721	20,991	4,802	4,814
	1,318,510		1,253,476	
Less: current maturities	(50,137)		(322,618)	
Long-term debt, less current maturities	$1,268,373		$ 930,858	

In January 2012, the Company redeemed at par its $12.4 million 1999 6.1% Series A fixed-rate IDRBs (originally due in 2038). In August 2012, the Company redeemed at par its $14.3 million 1999 5.95% Series C fixed-rate IDRBs (originally due in 2038).

In March 2012, the Company issued $250 million in 3.875% Senior Notes at a 0.034% discount. The notes will mature on April 1, 2022. Management used approximately $200 million of the net proceeds in connection with the repayment of the $200 million 7.625% Senior Notes that matured in May 2012. The remaining net proceeds were used for general corporate purposes.

In March 2012, the Company replaced the existing $300 million revolving credit facility that was to expire in May 2012 with a $300 million facility that is scheduled to expire in March 2017. Interest rates for the credit facility are calculated at either the London Interbank Offered Rate ("LIBOR") or the "alternate base rate," plus, in each case, an applicable margin that is determined based on the Company's senior unsecured debt rating. At the Company's current unsecured debt rating, the applicable margin is 1.125% for loans bearing interest with reference to LIBOR and 0.125% for loans bearing interest with reference to the

alternative base rate. Southwest has designated $150 million of the $300 million facility for long-term purposes and the remaining $150 million for working capital purposes. At December 31, 2012, $91 million was outstanding on the credit facility. Borrowings under the credit facility ranged from $0 during the second quarter of 2012 to a high of $130 million during November 2012. The effective interest rate on the long-term portion of the credit facility was 1.43% at December 31, 2012. There were no borrowings outstanding on the short-term portion of the credit facility at December 31, 2011 and 2012. (See Note 8 – 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 new program are calculated at the then current commercial paper rate. At December 31, 2012, $20 million was outstanding on the commercial paper program. The effective interest rate on the commercial paper program was 0.84% at December 31, 2012.

In February 2013, a notice of mandatory tender was sent to holders of the Clark County, Nevada 5.45% Series 2003C and 5.80% Series 2003E IDRBs. These IDRBs (totaling $45 million) are subject to mandatory tender on March 1, 2013 at a price of 100% plus accrued interest, and the Company intends to tender these IDRBs to the trustee for cancellation immediately following the mandatory tender, thereby extinguishing this debt. Therefore, these IDRBs are shown as current maturities in the Company's consolidated balance sheet. The Company will facilitate the redemption primarily from borrowings under its $300 million credit facility.

In June 2012, NPL replaced its existing $30 million revolving credit facility that was to expire in June 2013 with a $75 million facility that is scheduled to expire in June 2015. The credit facility was amended in October 2012 to temporarily increase the facility from $75 million to $85 million until December 29, 2012 and then reverted back to $75 million. Interest rates for the credit facility were also amended in October 2012 and are now 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, 2012, $41.6 million was outstanding on the NPL credit facility. The effective interest rate on NPL's credit facility was 0.97% at December 31, 2012.

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

	December 31, 2012	December 31, 2011
2003 Series A	1.71%	0.83%
2008 Series A	1.59%	1.62%
2009 Series A	1.14%	1.56%
Tax-exempt Series A	1.25%	2.22%

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):

2013	$ 50,137
2014	5,249
2015	46,705
2016	4,143
2017	137,049

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, 2012, the Company is in compliance with all of its covenants. Under the most restrictive of the covenants, the Company could issue over $1.7 billion in additional debt and meet the leverage ratio requirement. The Company has at least $700 million of cushion in equity relating to the minimum net worth requirement.

Note 8 — Short-Term Debt

As discussed in Note 7, Southwest replaced the existing $300 million credit facility that was to expire in May 2012 with a $300 million facility that is scheduled to expire in March 2017. Of the $300 million available under the facility, $150 million was designated by management for working capital purposes. The Company had no short-term borrowings outstanding at December 31 in either 2011 or 2012.

Note 9 — 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 $5 million in aggregate claims above $1 million in the policy year.

Note 10 – 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):

	2012	2011	2010
Employee Investment Plan cost	$ 4,707	$ 4,626	$ 4,583

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. The changes in actuarial gains and losses, prior service costs and transition assets or obligations pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are 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. The current 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 the continuing low interest rate environment for high-quality fixed income investments, the Company lowered the discount rate in 2012 from 2011. The methodology utilized to determine the discount rate was consistent with prior years. The weighted-average rate of compensation increase was also lowered (consistent with management's expectations overall) in 2012 from 2011 and the asset return assumption was unchanged between periods. The rates are presented in the table below:

	December 31, 2012	December 31, 2011
Discount rate	4.25%	5.00%
Weighted-average rate of compensation increase	2.75%	3.00%
Asset return assumption	8.00%	8.00%

The significant reduction in the discount rate will increase the expense level for 2013. Pension expense for 2013 is estimated to increase by $6.4 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.

	2012			2011		
	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)	$ 780,571	$ 33,827	$ 52,182	$ 662,134	$ 31,860	$ 46,765
Service cost	20,319	274	977	17,725	217	858
Interest cost	38,266	1,629	2,547	37,276	1,766	2,631
Plan amendments	-	-	2,423	-	-	-
Actuarial loss (gain)	92,409	4,111	2,775	89,922	2,427	2,835
Benefits paid	(28,753)	(2,468)	(1,200)	(26,486)	(2,443)	(907)
Benefit obligation at end of year (PBO/PBO/APBO)	902,812	37,373	59,704	780,571	33,827	52,182
Change in plan assets						
Market value of plan assets at beginning of year	521,829	-	29,944	475,931	-	29,640
Actual return on plan assets	68,174	-	4,454	2,384	-	(200)
Employer contributions	48,500	2,468	1,256	70,000	2,443	904
Benefits paid	(28,753)	(2,468)	(404)	(26,486)	(2,443)	(400)
Market value of plan assets at end of year	609,750	-	35,250	521,829	-	29,944
Funded status at year end	$(293,062)	$(37,373)	$(24,454)	$(258,742)	$(33,827)	$(22,238)
Weighted-average assumptions (benefit obligation)						
Discount rate	4.25%	4.25%	4.25%	5.00%	5.00%	5.00%
Weighted-average rate of compensation increase	2.75%	2.75%	2.75%	3.00%	3.00%	3.00%

Estimated funding for the plans above during calendar year 2013 is approximately $49 million of which $46 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, 2012	December 31, 2011
Retirement plan	$811,184	$699,269
SERP	35,362	32,695

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

	2013	2014	2015	2016	2017	2018-2022
Pension	$33.2	$34.9	$36.7	$38.5	$40.6	$234.4
PBOP	2.6	2.8	3.0	3.2	3.3	17.4
SERP	2.5	2.5	2.5	2.5	2.5	12.0

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 7.5% 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		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
(Thousands of dollars)									
Service cost	$ 20,319	$ 17,725	$ 16,932	$ 274	$ 217	$ 372	$ 977	$ 858	$ 856
Interest cost	38,266	37,276	35,614	1,629	1,766	2,045	2,547	2,631	2,491
Expected return on plan assets	(45,780)	(40,114)	(36,538)	-	-	-	(2,404)	(2,379)	(2,093)
Amortization of transition obligation	-	-	-	-	-	-	867	867	867
Amortization of net actuarial loss	23,883	14,348	10,478	683	631	1,155	1,031	590	489
Net periodic benefit cost	$ 36,688	$ 29,235	$ 26,486	$2,586	$2,614	$3,572	$ 3,018	$ 2,567	$ 2,610
Weighted-average assumptions (net benefit cost)									
Discount rate	5.00%	5.75%	6.00%	5.00%	5.75%	6.00%	5.00%	5.75%	6.00%
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	3.00%	3.25%	3.25%	3.00%	3.25%	3.25%	3.00%	3.25%	3.25%

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

	2012				2011				2010			
	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)	$ 74,853	$ 70,016	$4,111	$ 726	$ 135,492	$ 127,651	$2,427	$ 5,414	$ 9,058	$ 10,994	$(3,480)	$1,544
Amortization of transition obligation (b)	(867)	-	-	(867)	(867)	-	-	(867)	(867)	-	-	(867)
Amortization of net actuarial loss (b)	(25,597)	(23,883)	(683)	(1,031)	(15,569)	(14,348)	(631)	(590)	(12,122)	(10,478)	(1,155)	(489)
Prior service cost	2,423	-	-	2,423	-	-	-	-	-	-	-	-
Regulatory adjustment	(42,771)	(41,520)	-	(1,251)	(105,931)	(101,974)	-	(3,957)	(652)	(464)	-	(188)
Recognized in other comprehensive (income) loss	8,041	4,613	3,428	-	13,125	11,329	1,796	-	(4,583)	52	(4,635)	-
Net periodic benefit costs recognized in net income	42,292	36,688	2,586	3,018	34,416	29,235	2,614	2,567	32,668	26,486	3,572	2,610
Total of amount recognized in net periodic benefit cost and other comprehensive (income) loss	$ 50,333	$ 41,301	$6,014	$ 3,018	$ 47,541	$ 40,564	$4,410	$ 2,567	$ 28,085	$ 26,538	$(1,063)	$2,610

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, 2012 and December 31, 2011. The SERP has no assets. There were no transfers between Levels 1 and 2.

	December 31, 2012			December 31, 2011		
	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						
Cash equivalents	$ —	$ —	$ —	$ 20	$ 1	$ 21
Common stock						
Capital equipment	3,510	106	3,616	4,332	133	4,465
Chemicals/materials	6,741	204	6,945	7,425	227	7,652
Consumer goods	49,247	1,492	50,739	40,806	1,249	42,055
Energy and mining	39,454	1,195	40,649	39,080	1,196	40,276
Finance/insurance	28,861	874	29,735	23,808	729	24,537
Healthcare	29,615	897	30,512	26,070	798	26,868
Information technology	30,534	925	31,459	29,052	889	29,941
Services	25,316	767	26,083	17,417	533	17,950
Telecommunications/utilities	24,355	738	25,093	16,257	498	16,755
Other	20,298	615	20,913	22,473	688	23,161
Real estate investment trusts	6,572	199	6,771	5,779	177	5,956
Mutual funds	67,749	17,802	85,551	57,512	14,154	71,666
Government fixed income securities	18,663	565	19,228	5,727	175	5,902
Futures contracts	—	—	—	4	—	4
Total Level 1 Assets (1)	$350,915	$26,379	$377,294	$295,762	$21,447	$317,209
Level 2—Significant other observable inputs						
Commercial paper	$ 635	$ 19	$ 654	$ —	$ —	$ —
Government fixed income and mortgage backed securities	42,997	1,302	44,299	42,361	1,297	43,658
Corporate fixed income securities						
Asset-backed and mortgage-backed	16,637	504	17,141	16,969	519	17,488
Banking	17,966	544	18,510	16,192	496	16,688
Utilities	4,107	124	4,231	5,064	155	5,219
Other	28,925	876	29,801	25,769	789	26,558
Pooled funds and mutual funds	20,636	1,789	22,425	17,447	2,244	19,691
State and local obligations	1,273	39	1,312	936	29	965
Total Level 2 assets (2)	$133,176	$ 5,197	$138,373	$124,738	$ 5,529	$130,267

	December 31, 2012			December 31, 2011		
	Qualified Retirement Plan	PBOP	Total	Qualified Retirement Plan	PBOP	Total
Level 3—Significant unobservable inputs						
Commingled equity funds	$123,719	$ 3,748	$127,467	$ 97,295	$ 2,978	$100,273
Total Level 3 assets (3)	$123,719	$ 3,748	$127,467	$ 97,295	$ 2,978	$100,273
Total Plan assets at fair value	$607,810	$35,324	$643,134	$517,795	$29,954	$547,749
Insurance company general account contracts (4)	4,626	—	4,626	4,952	—	4,952
Total Plan assets (5)	$612,436	$35,324	$647,760	$522,747	$29,954	$552,701

(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 an impact fee to be applied to redemptions and subscriptions of $5 million or greater.

(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 $2,760,000 (qualified retirement plan – $2,685,000, PBOP – $75,000) and $928,000 (qualified retirement plan – $918,000, PBOP – $10,000) for 2012 and 2011, 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)

	Commingled Equity Funds
(Thousands of dollars):	
Balance, December 31, 2010	$ 97,469
Actual return on plan assets:	
Relating to assets still held at the reporting date	(8,442)
Relating to assets sold during the period	246
Purchases	12,000
Sales	(1,000)
Settlements	—
Transfers in and/or out of Level 3	—
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

Note 11 – Stock-Based Compensation

At December 31, 2012, the Company had three stock-based compensation plans: a stock option plan, a performance share stock plan, and a restricted stock/unit plan. Total stock-based compensation expense recognized in the consolidated statements of income is shown in the table below (in thousands):

	2012	2011	2010
Stock-based compensation expense, net of related tax benefits	$7,396	$7,262	$5,874
Stock-based compensation related tax benefits	4,533	4,451	3,600

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):

	2012		2011		2010	
	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	177	$27.28	369	$28.04	651	$27.49
Exercised during the year	(52)	25.25	(192)	28.75	(273)	26.67
Forfeited or expired during the year	—	—	—	—	(9)	29.51
Outstanding and exercisable at year end	125	$28.13	177	$27.28	369	$28.04

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):

	2012	2011	2010
Outstanding and exercisable	$1,788	$2,697	$3,186
Exercised	928	1,949	1,689

	December 31, 2012	December 31, 2011	December 31, 2010
Market value of Southwest Gas stock	$42.41	$42.49	$36.67

The weighted-average remaining contractual life for outstanding options was 2.7 years for 2012. All outstanding options are fully vested and exercisable. The following table summarizes information about stock options outstanding at December 31, 2012 (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	30	1.2 Years	$22.54
$25.00 to $26.10	34	2.5 Years	$25.74
$29.08 to $33.07	61	3.5 Years	$32.21

The Company received $1.4 million in cash from the exercise of options during 2012 and a corresponding tax benefit of $363,000 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 then issued as common stock. 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, 2012 (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	361	$30.66	176	$32.65
Granted	105	41.34	94	41.34
Dividends	10		5	
Forfeited or expired	—	—	—	—
Vested and issued*	(128)	25.68	(68)	31.61
Nonvested/unissued at December 31, 2012	348	$36.03	207	$37.18

*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 2011 and 2010 was $37.87 and $29.04, respectively.

As of December 31, 2012, total compensation cost related to nonvested performance shares and restricted stock/units not yet recognized is $3.8 million.

Note 12 – 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 2008, and is subject to examination by the various state taxing authorities for years after 2007.

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):

	2012	2011	2010
Tax-related interest income	$24	$100	$500

Tax-related interest receivable and payable included in the consolidated balance sheets are shown in the table below (in thousands):

	2012	2011
Tax-related interest receivable (payable)	$—	$6

The Company had no uncertain tax liabilities at December 31, 2012, or at any time during 2012. The Company expects no change in unrecognized tax benefits in the next twelve months.

A reconciliation of the beginning and ending amount of unrecognized tax benefits in 2011 is as follows (thousands of dollars):

	2011
Unrecognized tax benefits at beginning of year	$ 1,445
Gross increases – tax positions in prior period	—
Gross decreases – tax positions in prior period	—
Gross increases – current period tax positions	—
Gross decreases – current period tax positions	—
Settlements	—
Lapse of statute of limitations	(1,445)
Unrecognized tax benefits at end of year	$ —

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

Year Ended December 31,	2012	2011	2010
Current:			
Federal	$ 2,296	$ (265)	$ 4,204
State	5,744	2,122	4,442
	8,040	1,857	8,646
Deferred:			
Federal	65,551	58,584	44,778
State	1,685	2,862	1,501
	67,236	61,446	46,279
Total income tax expense	$75,276	$63,303	$54,925

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

Year Ended December 31,	2012	2011	2010
Deferred federal and state:			
Property-related items	$64,249	$51,710	$43,420
Purchased gas cost adjustments	1,755	(92)	(315)
Employee benefits	564	11,766	8,753
All other deferred	1,529	(1,070)	(4,711)
Total deferred federal and state	68,097	62,314	47,147
Deferred ITC, net	(861)	(868)	(868)
Total deferred income tax expense	$67,236	$61,446	$46,279

The consolidated effective income tax rate for the period ended December 31, 2012 and the two prior periods differ from the federal statutory income tax rate. The sources of these differences and the effect of each are summarized as follows:

Year Ended December 31,	2012	2011	2010
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state taxes	2.6	2.7	2.8
Property-related items	0.2	0.2	0.2
Effect of income tax settlements	—	(0.9)	(0.3)
Tax credits	(0.4)	(0.6)	(0.5)
Company owned life insurance	(1.3)	(0.1)	(2.3)
All other differences	0.1	(0.1)	(0.2)
Consolidated effective income tax rate	36.2%	36.2%	34.7%

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

December 31,	2012	2011
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 3,211	$ 3,743
Employee benefits	27,097	24,605
Alternative minimum tax credit	18,467	17,411
Net operating losses and credits	36,206	59,096
Interest rate swap	11,164	13,352
Other	17,866	15,099
Valuation allowance	(141)	(142)
	113,870	133,164
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	652,380	611,022
Regulatory balancing accounts	2,498	743
Property-related items previously flowed through	1,729	2,797
Unamortized ITC	5,131	5,992
Debt-related costs	4,602	4,379
Other	16,626	11,914
	682,966	636,847
Net deferred tax liabilities	$569,096	$503,683
Current	$ (47,088)	$ (53,435)
Noncurrent	616,184	557,118
Net deferred tax liabilities	$569,096	$503,683

At December 31, 2012, the Company has a federal net operating loss carryforward of $103 million and a federal general business credit carryforward of $306,000, both of which expire in 2031. The Company also has a net capital loss carryforward of $320,000, which expires in 2016. The Company also has charitable contribution carryforwards of $892,000 and $743,000, which expire in 2016 and 2017, respectively. On January 2, 2013, the American Taxpayer Relief Act of 2012 ("Taxpayer Relief Act") was signed into law. The Taxpayer Relief Act extended the availability of the 50% bonus depreciation deduction through 2013. As a result, the Company will not utilize any of the current alternative minimum tax credit in 2013.

Note 13 – 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.

The fixed-price contracts and Swaps are utilized by Southwest under its volatility mitigation programs to effectively fix the price on a portion (currently 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 2013 through March 2015. 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, 2012	December 31, 2011
Contract notional amounts	14,579	10,827

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, 2012, 2011, and 2010 and their location in the income statements (thousands of dollars):

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

Instrument	Location of Gain or (Loss) Recognized in Income on Derivative	2012	2011	2010
Swaps	Net cost of gas sold	$(4,854)	$(18,201)	$(27,690)
Swaps	Net cost of gas sold	4,854*	18,201*	27,690*
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 to hedge the risk of interest rate variability during the period leading up to the planned issuance of fixed-rate debt to replace $200 million of debt that matured in February 2011 and $200 million that matured in May 2012. The counterparties to each agreement were four major banking institutions. The first FSIRS was a designated cash flow hedge and terminated in December 2010 concurrent with the related issuance of $125 million 4.45% 10-year Senior Notes. The second FSIRS was also a designated cash flow hedge and had a notional amount of $100 million. It terminated in March 2012 concurrent with the related issuance of $250 million 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 was recognized in income (ineffective portion) for either FSIRS during any period, including the periods presented in the following table.

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

	Year Ended December 31, 2012	Year Ended December 31, 2011
(Thousands of dollars)		
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 FSIRS and their location in the balance sheets (thousands of dollars):

Fair values of derivatives not designated as hedging instruments:

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)

December 31, 2011 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
Swaps	Other current liabilities	$ —	$(11,122)	$(11,122)
Swaps	Other deferred credits	—	(621)	(621)
Total		$ —	$(11,743)	$(11,743)

Fair values of derivatives designated as hedging instruments:

December 31, 2011 Instrument	Balance Sheet Location	Asset Derivatives	Liability Derivatives	Net Total
FSIRS	Other current liabilities	$ —	$(24,713)	$(24,713)

As noted above, the FSIRS that remained at December 31, 2011 terminated in March 2012.

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.

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.

(Thousands of dollars)	Year ended December 31, 2012	Year ended December 31, 2011	Year ended December 31, 2010
Paid to counterparties	$14,843	$17,283	$16,574
Received from counterparties	$ 634	$ —	$ 831

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

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

December 31, 2011 Instrument	Balance Sheet Location	Net Total
Swaps	Prepaids and other current assets	$11,122
Swaps	Deferred charges and other assets	621

Fair Value Measurements. The estimated fair values of Southwest's Swaps were determined at December 31, 2012 and 2011 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 estimated fair value of Southwest's FSIRS at December 31, 2011 was determined using a discounted cash flow model that utilized forward interest rate curves. The inputs to the model were the terms of the FSIRS. These Level 2 inputs were observable in the marketplace throughout the full term of the FSIRS, but were credit-risk adjusted with no significant impact to the overall fair value measure. See Note 5 – Other Comprehensive Income and Accumulated Other Comprehensive Income ("AOCI") for more information on the FSIRS.

See Note 10 – Pension and Other Postretirement Benefits for definitions of the levels of the fair value hierarchy. 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:

Level 2 - Significant other observable inputs

	December 31, 2012	December 31, 2011
(Thousands of dollars)		
Assets at fair value:		
Deferred charges and other assets - Swaps	$ 6	$ —
Liabilities at fair value:		
Other current liabilities - Swaps	(2,076)	(11,122)
Other deferred credits - Swaps	(319)	(621)
Other current liabilities - FSIRS	—	(24,713)
Net Assets (Liabilities)	$(2,389)	$(36,456)

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

Note 14 - 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, 2012	December 31, 2011
Accounts receivable for NPL services	$8,179	$6,205

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, 2012 is as follows (thousands of dollars):

2012	Gas Operations	Construction Services	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	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

2010	Gas Operations	Construction Services	Total
Revenues from unaffiliated customers	$1,511,907	$257,213	$1,769,120
Intersegment sales	—	61,251	61,251
Total	$1,511,907	$318,464	$1,830,371
Interest revenue	$ 158	$ 36	$ 194
Interest expense	$ 77,025	$ 564	$ 77,589
Depreciation and amortization	$ 170,456	$ 20,007	$ 190,463
Income tax expense	$ 47,073	$ 7,852	$ 54,925
Segment net income	$ 91,382	$ 12,495	$ 103,877
Segment assets	$3,845,111	$139,082	$3,984,193
Capital expenditures	$ 188,379	$ 27,060	$ 215,439

Note 15 – Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
(Thousands of dollars, except per share amounts)				
2012				
Operating revenues	$657,645	$409,768	$371,799	$488,566
Operating income	134,623	15,380	6,310	115,211
Net income (loss)	78,919	(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
2011				
Operating revenues	$628,440	$388,505	$352,592	$517,651
Operating income	126,335	20,568	1,253	101,924
Net income (loss)	68,549	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
2010				
Operating revenues	$668,751	$385,825	$307,683	$468,112
Operating income	121,732	24,031	184	86,170
Net income (loss)	64,648	(933)	(4,823)	44,985
Basic earnings (loss) per common share*	1.43	(0.02)	(0.11)	0.99
Diluted earnings (loss) per common share*	1.42	(0.02)	(0.11)	0.98

* 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. 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, 2012. The effectiveness of the Company’s internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 27, 2013

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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.

Las Vegas, Nevada
February 27, 2013

Board of Directors and Officers

Directors
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Las Vegas, Nevada
Executive Vice President and
Chief Business Development Officer
Boyd Gaming Corporation

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Senior Vice President and
General Counsel
Arizona State University

Thomas E. Chestnut
Tucson, Arizona
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Chief Executive Officer
Chestnut Construction
Company

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

LeRoy C. Hanneman, Jr.
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Retired Construction
Executive
Private Investor

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Southwest Gas Corporation

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Avansino, Melarkey, Knobel,
Mulligan & McKenzie
Chairman of the Board of Directors
Southwest Gas Corporation

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Deloitte & Touche LLP

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of Directors
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Senior Vice President/Chief
Financial Officer

Eric DeBonis
Senior Vice President/
Operations

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

John P. Hester
Senior Vice President/Regulatory
Affairs and Energy Resources

Laura Lopez Hobbs
Senior Vice President/Human
Resources and Administration

Edward A. Janov
Senior Vice President/
Corporate Development

William N. Moody
Senior Vice President/Staff
Operations and Technology

Justin L. Brown
Vice President/Pricing

Garold L. Clark
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Arizona Division

Jose L. Esparza, Jr.
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Luis F. Frisby
Vice President/Central Arizona
Division

Randall P. Gabe
Vice President/Gas Resources

Bradford T. Harris
Vice President/Southern
California Division

Kenneth J. Kenny
Vice President/Finance/Treasurer

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

Anita M. Romero
Vice President/Information
Services

Jerome T. Schmitz
Vice President/Engineering

Donald L. Soderberg
Vice President/Risk Management
and Compliance Officer

Christopher W. Sohus
Vice President/Southern
Nevada Division

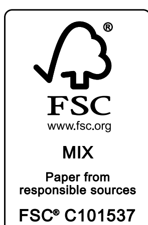
Julie M. Williams
Vice President/Northern
Nevada Division

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 9, 2013 at 10:00 a.m. at the Las Vegas Chamber of Commerce
6671 Las Vegas Blvd. South, Suite 300, Las Vegas, Nevada.

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 64874
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 2012 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 64856
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 2012.

SOUTHWEST GAS CORPORATION

5241 Spring Mountain Road, Las Vegas, Nevada 89150

SWX1AR2012