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12-31-2004

SOUTHWEST GAS CORPORATION

Annual Report 2004

Fire pits. Tiki torches. Barbecues. Natural gas amenities are essential in the creation of the perfect "outdoor living room." Not only do they provide glamour to backyard parties year round, but the romantic glow cast by a tiki torch, the warmth of a natural gas fire pit, and the aroma of food cooking on a grill can arouse all your senses. The natural gas outdoor lifestyle comes easily in Southwest Gas Corporation's service territories of Arizona, Nevada and parts of northeastern and southeastern California. According to the U.S. Census Bureau, in 2004 Nevada led the nation with a 4.1 percent population growth rate, Arizona followed with 3 percent, and California was one of the 10 most populous states. A company with a history of forward thinking, Southwest Gas is once again raising the industry bar by expanding natural gas uses from under the roof to under the stars.

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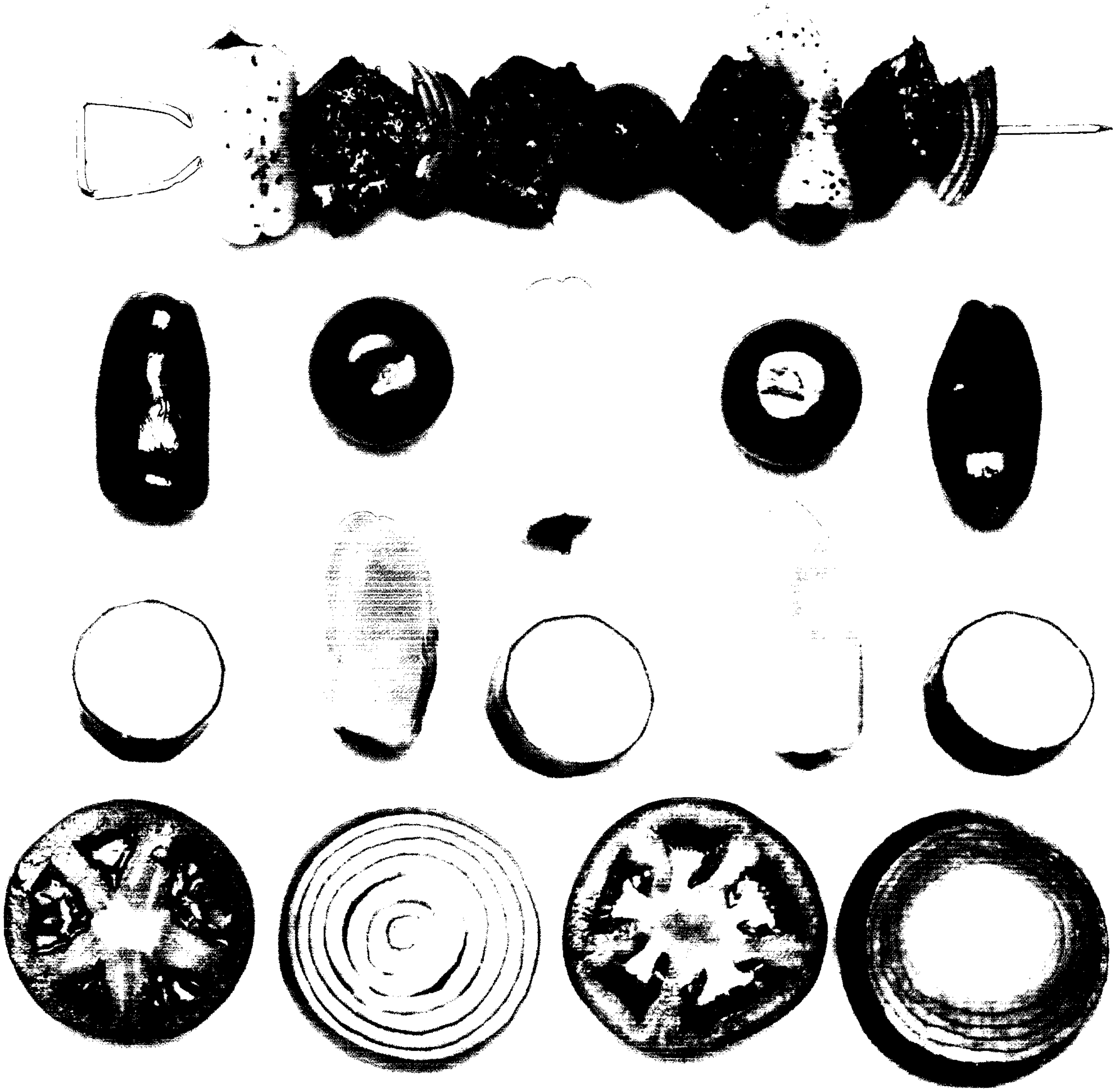
Natural Gas Today

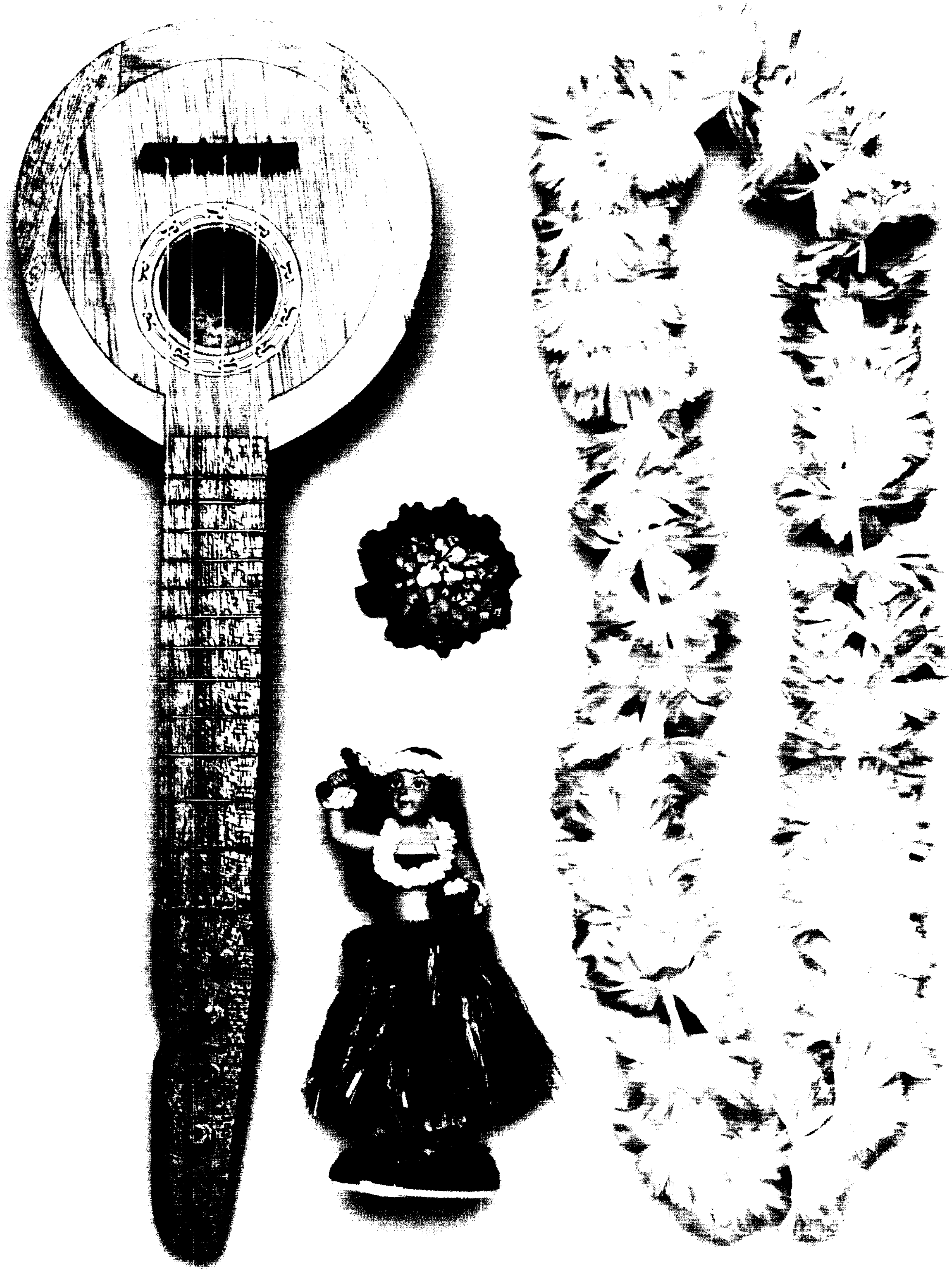


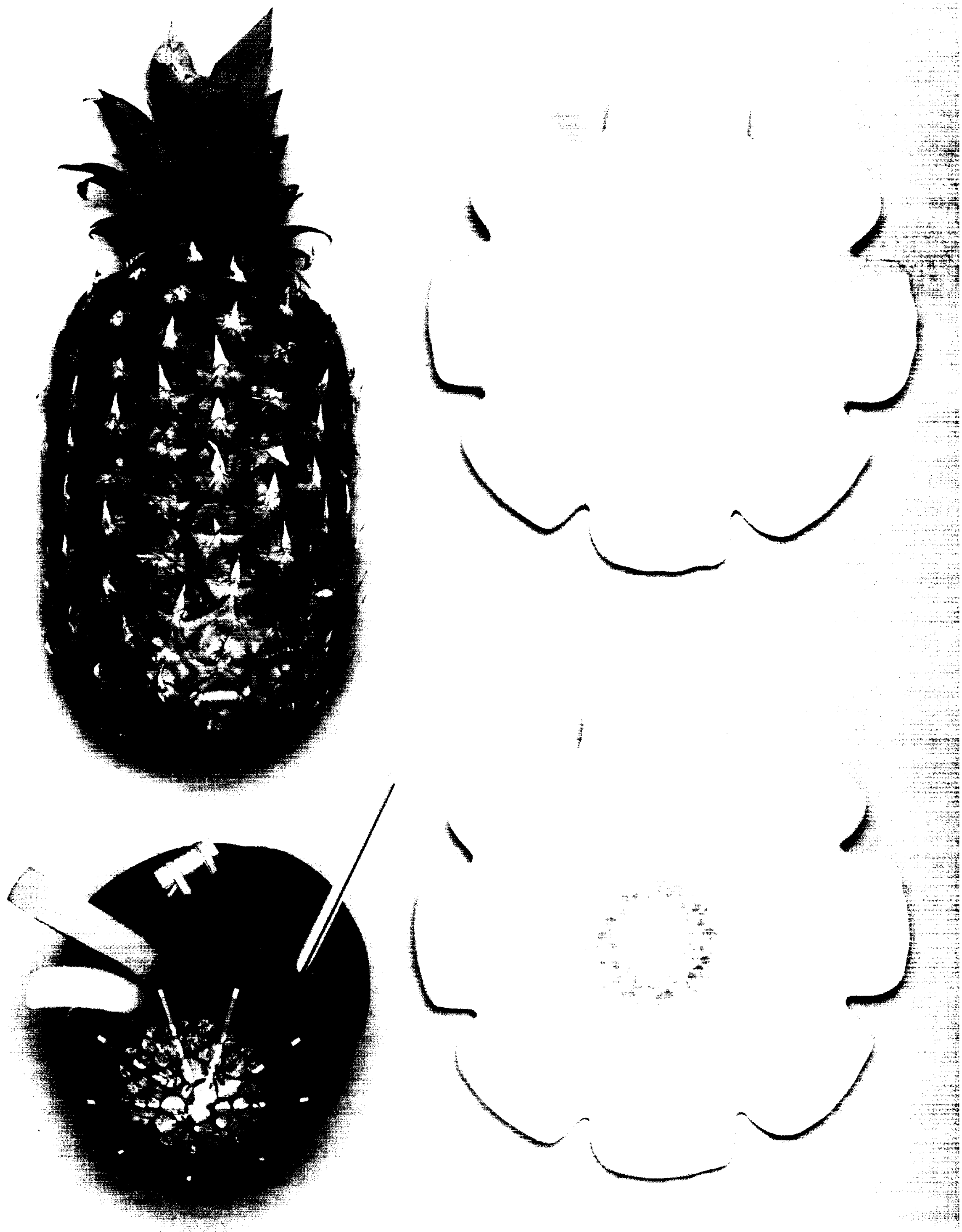
Your backyard never looked so good.

And, entertaining has never been so easy. With just the touch of a button, the grill of your dreams can help bring all your senses to life. From tantalizing your taste buds with delicious foods and heavenly aromas, to inspiring sizzling conversations, natural gas grills add spice to any backyard party. Sleek, high-tech grills add style to your landscape, and are fast, reliable, and easy to use. The increased use of advanced technologies, however, applies to more than just natural gas appliances. In order to help its employees work more efficiently and maintain a high standard of customer service, Southwest Gas continues to review and implement the latest in business technologies. It is this commitment to innovation that has helped the Company maintain one of the highest customer-to-employee ratios in the industry.

Natural Gas BBQ

Natural gas grills are ready to go when you're ready to grill. Their precise temperature controls and a flame that never runs on empty help you prepare mouthwatering barbecue any time of the day or night. If you're tired of running to the store for charcoal, lighter fluid, or propane, call the Southwest Gas Energy Specialists, 1-800-OK-GAS-OK (1-800-654-2765), for a list of natural gas barbecue dealers in your area. (Barbeques courtesy of: Westar Kitchen and Bath)



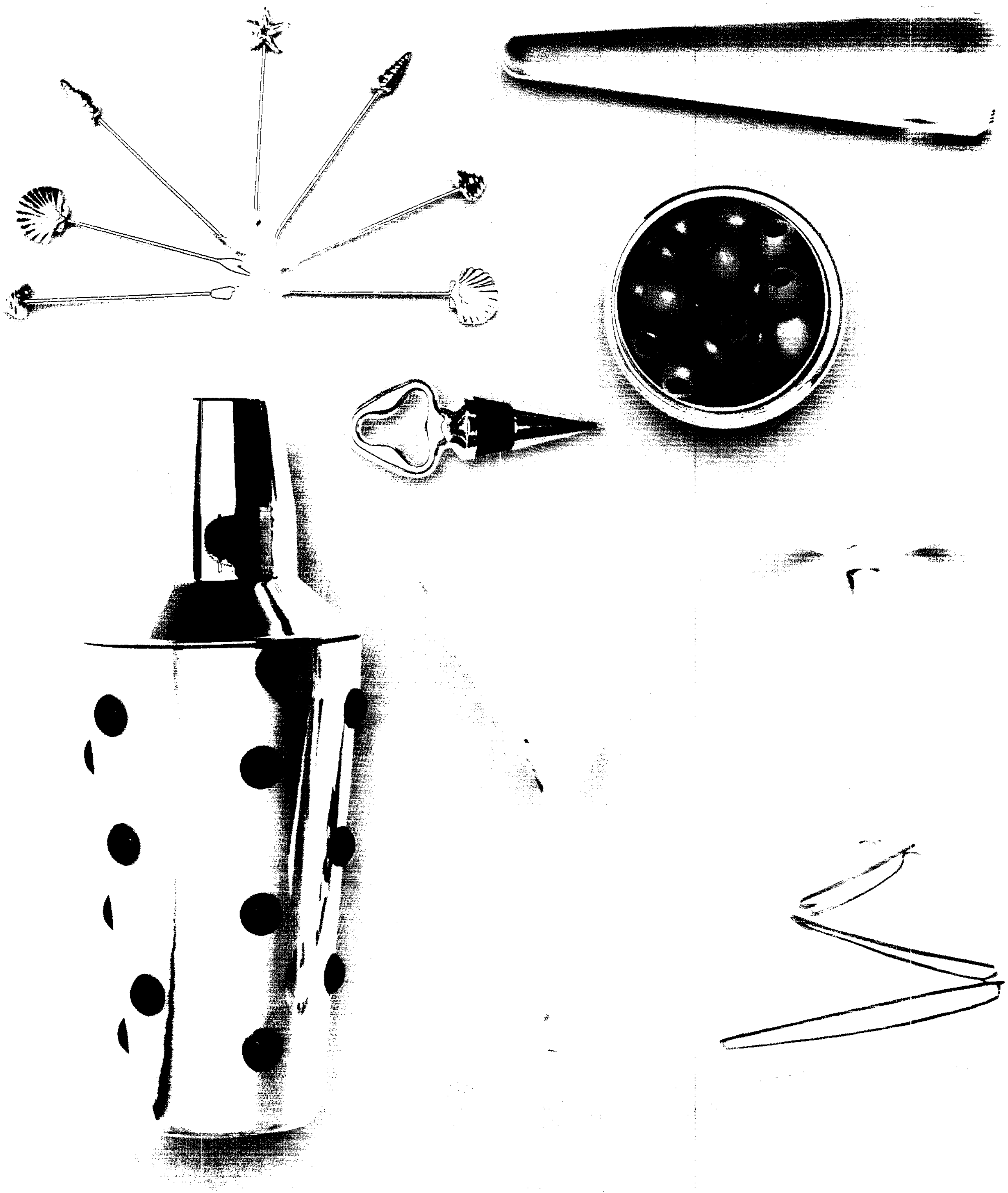


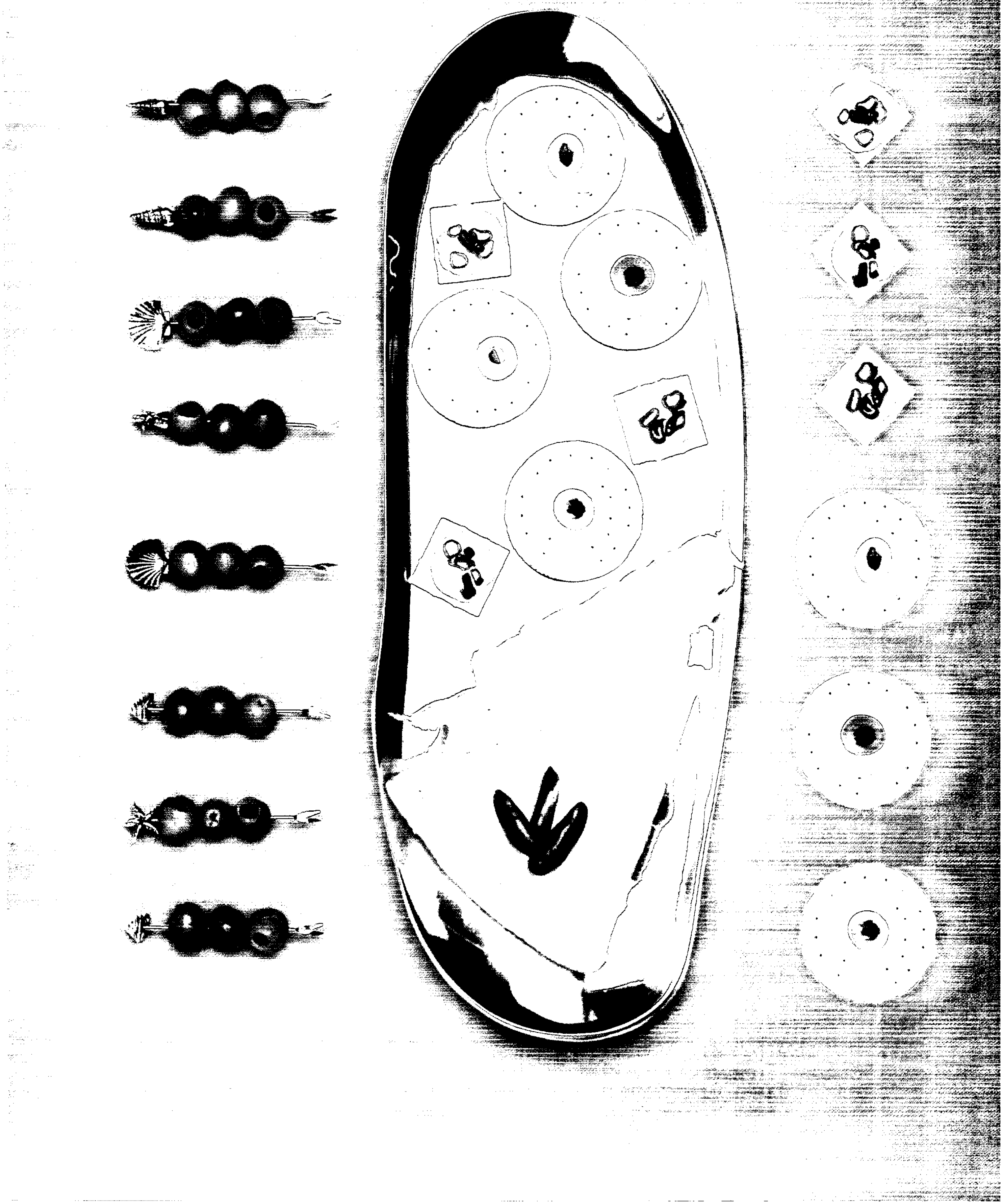
A night in the tropics is never more than a few feet away,

thanks to the soft illumination of the natural gas tiki torch in your backyard. Along with creating the atmosphere of a tropical paradise, tiki torches attractively add the right amount of light to your yard and walkways. Builders, landscapers, and restaurateurs can learn how to create a tropical retreat for their clients by visiting Southwest's new Outdoor Living Demonstration Center. In 2004, the Southern Nevada Division partnered with several vendors to transform a 6,000 square-foot courtyard into a state-of-the-art facility featuring a fire pit, fireplace, tiki torches, gaslights, heaters and barbecues. Thanks to this cooperative effort, Southwesters can now experience more of what natural gas has to offer.

Outdoor Gas Lighting

Natural gas tiki torches can add charm and value to your property for years to come. Easily installed into the ground or mounted on posts, tiki torches are a wonderful addition to any backyard. For more information on outdoor lifestyle products like the tiki torches, call the Southwest Gas Energy Specialists at 1-800-OK-GAS-OK (1-800-654-2765). (Tiki Torches courtesy of: Gaslite America West.)





What better place to have a good time than in your own backyard.

Having more than 88,000 first-time meter sets and acquiring more than 102,000 new builder commitments is something to celebrate. What better place to have a good time than in your own backyard? Of course, a perfect outdoor party should include a natural gas fire pit. Not only does the instant flame provide a chic aura, but the fire pit is the perfect place to gather around and share food, fun, and friendship.

Natural Gas Fire Pit

You can add a touch of warmth to your next outdoor party with a natural gas fire pit. The flickering flames not only bring the ambiance of a cozy campfire into your own backyard, but it's a great place to spark up a conversation. Convenient, reliable, and easily installed, a fire pit is the perfect enhancement to any landscape. For more information, call the Southwest Gas Energy Specialists at 1-800-OK-GAS-OK (1-800-654-2765). (Fire Pit courtesy of: Gaslite America West.)

Fellow Shareholders

2004 showed solid improvement in the Company's earnings. Rate relief in California and Nevada, a return to more normal weather patterns, record customer growth, and a stellar contribution from our pipeline construction subsidiary combined to generate earnings per share of $1.61, a 41 percent increase over the $1.14 posted in 2003.

In our fast growing service territories, rate relief continues to be critical to our financial performance. The California Public Utilities Commission (CPUC) approved annualized general rate relief for the Company's California jurisdictions of $6.7 million in the first quarter. Additionally, during the third quarter, the Public Utilities Commission of Nevada (PUCN) approved an annualized general rate increase in the Nevada jurisdictions totaling $13.7 million.

You may recall that weather was much warmer than normal during 2003. In fact, 2003 was the 2nd warmest year in Nevada and the 5th warmest year in Arizona overall in the last 109 years. In contrast, 2004 weather cooperated with cooler temperatures, and the resulting heating degree days, returning to more normal levels, which resulted in a notable improvement in operating margin.

2004 will mark the fifth time that we have reported record customer growth during the last decade, and...based on everything we read and hear...we are likely to report robust growth for the foreseeable future. In 2004, we added 82,000 customers for a growth rate of 5.4%, about three times the industry average.

Northern Pipeline Construction Co., our wholly owned subsidiary, achieved record net income of $8.4 million during 2004, compared to $4.3 million in 2003. Profitable bid work, increased workload under existing contracts, and a positive equipment resale market all contributed to a remarkable year. You might say that "the planets aligned" in 2004, and a repeat performance will likely be challenging in 2005.

Many of the Company initiatives undertaken in years past are continuing to yield positive benefits. Marketing strategies, judicious investments in technology and changes in operating activities have allowed the Company to see dramatic results.

Aggressive marketing strategies that were initiated more than a decade ago...to combat an all electric home alternative in the desert...have created a strong demand for natural gas. We currently enjoy a healthy system-wide average market share of 90 percent in our service territories in new home construction. As we've mentioned in prior annual reports, lifestyle is a significant part of our marketing strategy and, as you can see from the theme of this year's annual report, our sales efforts extend beyond the traditional uses of natural gas...cooking, space heating, clothes drying and water heating...to such outdoor amenities as tiki torches, open barbecue pits, outdoor fireplaces and patio heaters, gas lighting and outdoor kitchens. As expected robust growth continues, Southwest will aggressively promote these amenities to builders to give them a competitive edge as they market their sub-divisions. As an example, Southwest worked jointly with vendors of these amenities and outdoor landscapers to create a stunning demonstration courtyard in the Southern Nevada Division operations center. It is a real showpiece and has already proved invaluable in promoting the many uses of natural gas. The pictures in this year's annual report were taken in the courtyard.

We continue to roll out our new Work Management System which electronically tracks all construction, operations and maintenance work from engineering design to closing records. All of our employees in the field have on-board computers. This allows us to deliver work schedules over the airways as the employees are leaving home, thus letting them get to their first order without the delay of first reporting to an office location. This change alone has resulted in a dramatic increase in productivity and customer satisfaction. Additionally, all of our system maps are stored and updated electronically and use a GPS to ensure faster facility locating. Considering that we have crews working over a growing three-state area, the need to constantly update maps is a daunting task. Now, when our construction crews pull into an operations center, their computers are automatically uploaded with the latest changes. No more sitting in a truck with paper maps trying to figure out which sections to replace.

The investments we have made in technology and changes to our operating procedures have enabled us to contain costs and achieve an overall customer-to-employee ratio of 633 to 1, one of the best productivity ratios in the industry. In fact, under this measure we have experienced a 50 percent improvement in our productivity during the last decade, adding approximately 633,000 customers and only 189 employees.

We continue to face challenges, some that confront the industry and others that are unique to Southwest Gas. As we've discussed before, and as you have probably experienced in your gas bills, high natural gas prices continue to be a vexing problem for the industry. We, like most natural gas distribution utilities, must purchase all of our natural gas supplies in the open market. The market has been affected by government energy policies that have encouraged the use of clean-burning natural gas...to meet ever increasing needs, such as electric generation...yet restricted certain areas from exploration for new supplies. Until Congress addresses these national energy policy issues, the supply/demand balance will remain tight and prices will likely stay at higher levels. We believe solutions exist, but they will take time and significant investment to implement. The continuing challenge for policy makers will be to timely strike compromises between those with varying agendas. In the meantime, we must pass the higher cost of natural gas on to consumers, and we will continue to pursue a purchasing strategy that is designed to mitigate volatility in customer bills and pass the scrutiny of regulatory review.

Managing extreme growth has become a way of life for our management team and we have maintained a consistent focus on our core business...providing safe and reliable natural gas service to our customers. Our high customer satisfaction ratings and productivity statistics point to the commendable efforts of our employees. However, our principal challenge remains...we must continue to take steps to improve our earnings.

To improve our earnings, a principal focus must be on improving the adequacy and design of the rates our customers pay for the natural gas service we deliver. We believe the benefits of making such improvements will accrue to both customers and shareholders. Over time, improved earnings will lead to a stronger balance sheet which, in turn, should lead to higher credit ratings and a lower cost of capital. A lower cost of capital would be reflected in the rates customers pay.

In every general rate case we file, we request rates of return that are competitive and adequate given the risks of our business. This is extremely important to our company as we must access sources of capital to meet the robust growth in our service areas.

The substantial majority of our costs to provide natural gas service to customers...including the cost of capital...are fixed. However, regulatory commissions have historically favored rate designs that permit cost recovery based mostly on the quantities of natural gas consumed. This has unduly exposed the company's financial performance to the vagaries of weather and the effects of conservation measures taken by customers reacting to rising natural gas prices.

In the most recent California and Nevada general rate cases, we proposed several alternatives to address the rate design issue. In California, the approved rate design will substantially protect authorized operating margin and, in Nevada, the approved rate design will mitigate some of the exposure. We also proposed similar alternatives for rate design changes in our Arizona general rate case now pending before the commission in that state. We will continue to work with our regulators to make further progress to bring more stability to earnings and cash flows.

Finally, as mentioned in last year's letter, 2004 marked a year of transition in the membership of the Board of Directors and in senior management. However, the current Board and management continue to maintain a consistent focus on those elements that have allowed us to be successful:

/ Remaining focused on core competencies
/ Continuing to maximize efficiency and productivity
/ Continuing to be aggressive in managing growth
/ Striving to exceed our customers' expectations
/ Remaining watchful and positioned to seize strategic growth opportunities

We firmly believe that pursuing these strategies will, over time, increase the value of your investment in Southwest Gas.

Thomas Y. Hartley, Chairman of the Board

Jeffrey W. Shaw, Chief Executive Officer

George C. Biehl
Executive Vice President,
Chief Financial Officer and
Corporate Secretary

Jeffrey W. Shaw
Chief Executive Officer

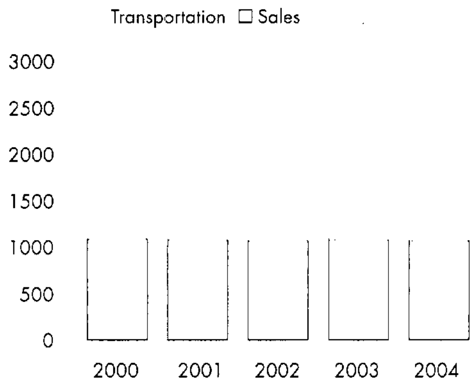
James P. Kane
President

Stock Prices & Trading Volume per Year

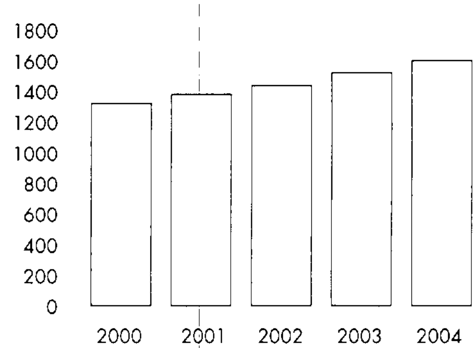
(stock prices in dollars, volume in millions)

Fireplace courtesy of: Metropolitan Outdoor Products (opposite)

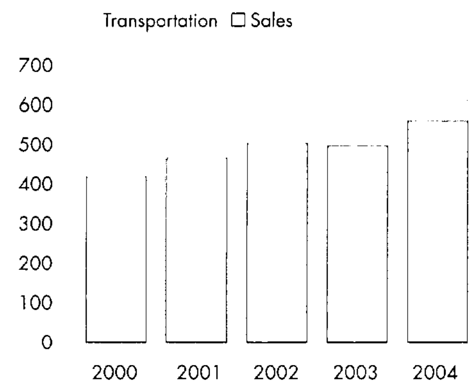
Throughput
(in millions of therms)



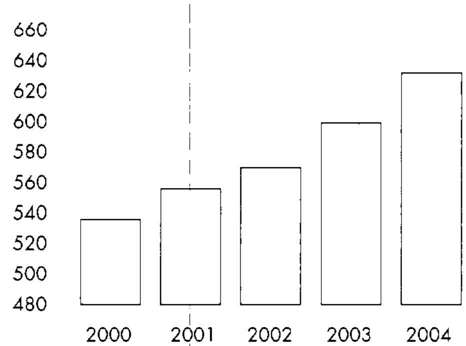
Number of Gas Customers
(in thousands)



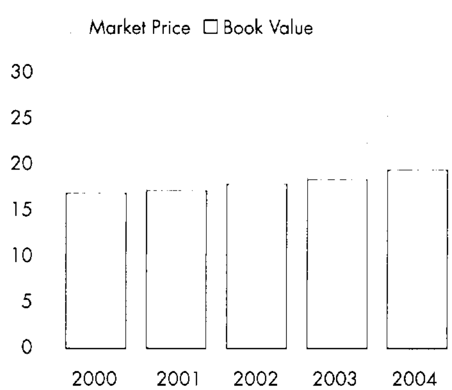
Margin
(in millions of dollars)



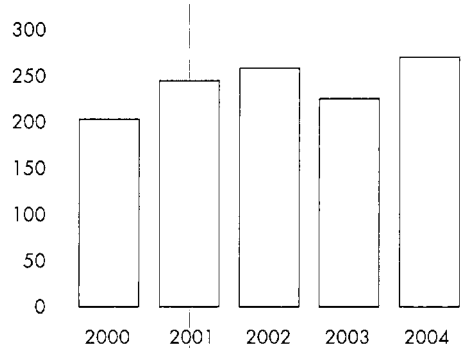
Customers per Employee



Market Price Relative to Book Value
(in dollars)

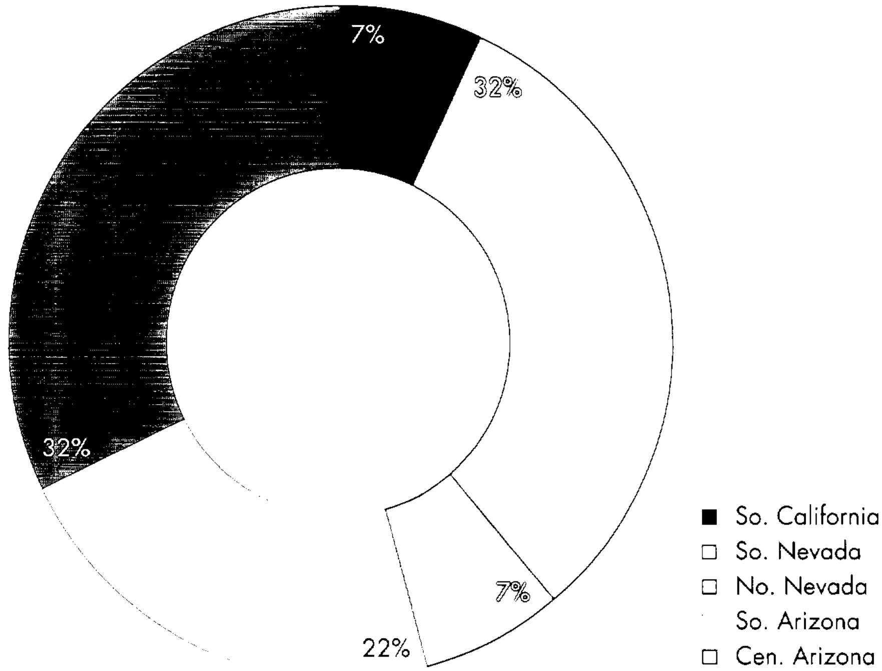


Construction Expenditures Gas Segment
(in millions of dollars)



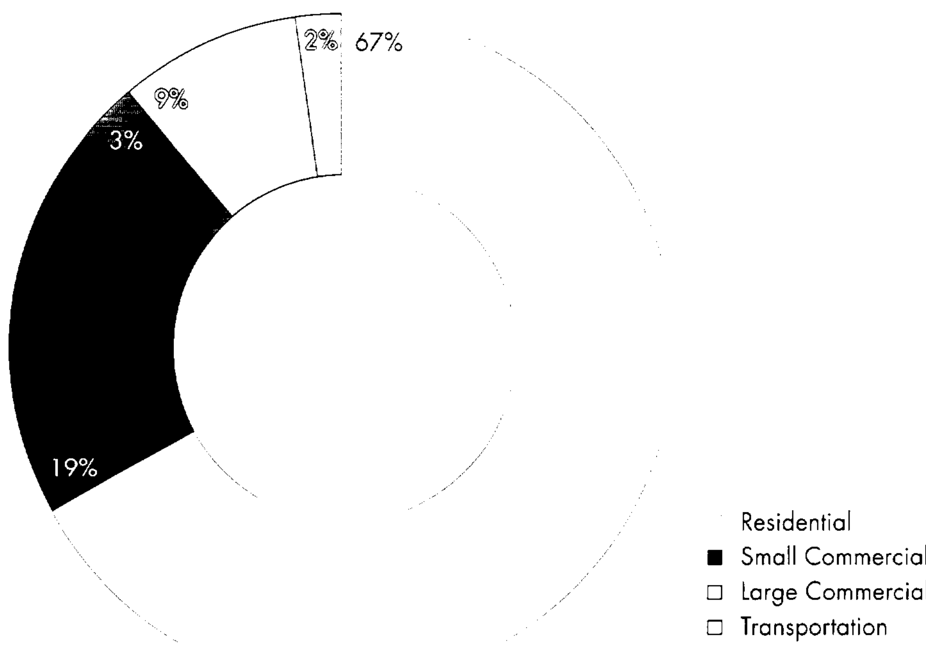
Customers by Division

(December 31, 2004)



Margin by Customer Class

(2004)



Financial Data

Consolidated Selected Financial Statistics

Year Ended December 31, (Thousands of dollars, except per share amounts)	2004	2003	2002	2001	2000
Operating revenues	$1,477,060	$1,231,004	$1,320,909	$1,396,688	$1,034,087
Operating expenses	1,307,293	1,095,899	1,174,410	1,262,705	905,457
Operating income	$ 169,767	$ 135,105	$ 146,499	$ 133,983	$ 128,630
Net income	$ 56,775	$ 38,502	$ 43,965	$ 37,156	$ 38,311
Total assets at year end	$2,938,116	$2,608,106	$2,432,928	$2,369,612	$2,232,337
Capitalization at year end					
Common equity	$ 705,676	$ 630,467	$ 596,167	$ 561,200	$ 533,467
Mandatorily redeemable preferred trust securities	—	—	60,000	60,000	60,000
Subordinated debentures	100,000	100,000	—	—	—
Long-term debt	1,162,936	1,121,164	1,092,148	796,351	896,417
	$1,968,612	$1,851,631	$1,748,315	$1,417,551	$1,489,884
Common stock data					
Return on average common equity	8.5%	6.3%	7.5%	6.8%	7.4%
Earnings per share	$ 1.61	$ 1.14	$ 1.33	$ 1.16	$ 1.22
Diluted earnings per share	$ 1.60	$ 1.13	$ 1.32	$ 1.15	$ 1.21
Dividends paid per share	$ 0.82	$ 0.82	$ 0.82	$ 0.82	$ 0.82
Payout ratio	51%	72%	62%	71%	67%
Book value per share at year end	$ 19.18	$ 18.42	$ 17.91	$ 17.27	$ 16.82
Market value per share at year end	$ 25.40	$ 22.45	$ 23.45	$ 22.35	$ 21.88
Market value per share to book value per share	132%	122%	131%	129%	130%
Common shares outstanding at year end (000)	36,794	34,232	33,289	32,493	31,710
Number of common shareholders at year end	23,743	22,616	22,119	23,243	24,092
Ratio of earnings to fixed charges	1.93	1.60	1.68	1.59	1.60

Natural Gas Operations

Year Ended December 31, (Thousands of dollars)	2004	2003	2002	2001	2000
Sales	$1,211,019	$ 984,966	$1,069,917	$1,149,918	$ 816,358
Transportation	51,033	49,387	45,983	43,184	54,353
Operating revenue	1,262,052	1,034,353	1,115,900	1,193,102	870,711
Net cost of gas sold	645,766	482,503	563,379	677,547	394,711
Operating margin	616,286	551,850	552,521	515,555	476,000
Expenses					
Operations and maintenance	290,800	266,862	264,188	253,026	231,175
Depreciation and amortization	130,515	120,791	115,175	104,498	94,689
Taxes other than income taxes	37,669	35,910	34,565	32,780	29,819
Operating income	$ 157,302	$ 128,287	$ 138,593	$ 125,251	$ 120,317
Contribution to consolidated net income	$ 48,354	$ 34,211	$ 39,228	$ 32,626	$ 33,908
Total assets at year end	$2,843,199	$2,528,332	$2,345,407	$2,289,111	$2,154,641
Net gas plant at year end	$2,335,992	$2,175,736	$2,034,459	$1,825,571	$1,686,082
Construction expenditures and property additions	$ 274,748	$ 228,288	$ 263,576	$ 248,352	$ 205,161
Cash flow, net					
From operating activities	$ 124,135	$ 187,122	$ 281,329	$ 103,848	$ 109,872
From investing activities	(272,458)	(249,300)	(243,373)	(246,462)	(203,325)
From financing activities	143,086	60,815	(49,187)	154,727	95,481
Net change in cash	$ (5,237)	$ (1,363)	$ (11,231)	$ 12,113	$ 2,028
Total throughput (thousands of therms)					
Residential	667,174	593,048	588,215	589,943	571,378
Small commercial	303,844	279,154	280,271	279,965	272,673
Large commercial	104,899	100,422	121,500	107,583	63,908
Industrial/Other	163,856	157,305	224,055	283,772	199,715
Transportation	1,258,265	1,336,901	1,325,149	1,268,203	1,482,700
Total throughput	2,498,038	2,466,830	2,539,190	2,529,466	2,590,374
Weighted average cost of gas purchased ($/therm)	$ 0.57	$ 0.46	$ 0.38	$ 0.55	$ 0.42
Customers at year end	1,613,000	1,531,000	1,455,000	1,397,000	1,337,000
Employees at year end	2,548	2,550	2,546	2,507	2,491
Degree days – actual	1,953	1,772	1,912	1,963	1,938
Degree days – ten-year average	1,913	1,931	1,963	1,970	1,991

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

Executive Summary

The following discussion of Southwest Gas Corporation and subsidiaries (the "Company") includes information related to regulated natural gas transmission and distribution activities and non-regulated activities.

The Company is comprised 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, transporting, and distributing natural gas in portions of Arizona, Nevada, and California. Southwest is the largest distributor 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 and transporter of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Consolidated Results of Operations

Year Ended December 31, (Thousands of dollars, except per share amounts)	2004	2003	2002
Contribution to net income			
Natural gas operations	$48,354	$34,211	$39,228
Construction services	8,421	4,291	4,737
Net income	$56,775	$38,502	$43,965
Earnings per share			
Natural gas operations	$ 1.37	$ 1.01	$ 1.19
Construction services	0.24	0.13	0.14
Consolidated	$ 1.61	$ 1.14	$ 1.33

See separate discussions at **Results of Natural Gas Operations** and **Results of Construction Services**. Average shares outstanding increased by 1.4 million between 2004 and 2003, and 807,000 between 2003 and 2002, primarily resulting from at-the-market offerings through the Equity Shelf Program and continuing issuances under the Dividend Reinvestment and Stock Purchase Plan ("DRSPP").

NPL achieved record net income of $8.4 million during 2004, compared to $4.3 million in 2003 due to profitable bid work, increased workload under existing contracts, and a positive equipment resale market. However, the convergence of favorable factors that resulted in the increase in contribution from construction services is not expected to be repeated in the near future.

As reflected in the table above, the natural gas operations segment accounted for an average of 87 percent of consolidated net income over the past three years. As such, management's main focus is on that segment.

Southwest's operating revenues are recognized from the distribution and transportation of natural gas (and related services) billed to customers. An estimate of the amount of natural gas distributed, 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 in revenues.

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 three principal factors affecting operating margin are general rate relief, weather, and customer growth.

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. General rate relief in California and Nevada provided an $18 million increase in margin during 2004 when compared to 2003. (See the section on **Rates and Regulatory Proceedings** for additional information). 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. The most recent rate cases, which affect about 40 percent of Southwest's business, included improvements in rate design which management believes will mitigate the impacts of weather and conservation on margin volatility.

Weather is a significant driver of natural gas volumes used by residential and small commercial customers and is the main reason for volatility in margin. Space heating-related volumes are the primary component of billings for these customer classes and are concentrated in the months of November to April for the majority of the Company's customers. Variances in temperatures from normal levels, especially during these months, have a significant impact on the margin and associated net income of the Company. A return to more normal temperatures in 2004 from the warm temperatures experienced in 2003 resulted in a $25 million increase in margin between years.

Customer growth, excluding acquisitions, has averaged five percent annually over the past ten years and five percent annually during the past three years. Incremental margin ($21 million in 2004) has accompanied this customer growth, but the costs associated with creating and maintaining the infrastructure needed to accommodate these customers also have been significant. The timing of including these costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings.

Management has attempted to mitigate the regulatory lag by being judicious in its staffing levels through the effective use of technology. During the past decade while adding nearly 633,000 customers, Southwest only increased staffing levels by 189. During this same period, Southwest's customer to employee ratio has climbed from 415/1 to 633/1, one of the best in the industry. It has accomplished this without sacrificing service quality. Examples of technological improvements over the last few years include electronic order routing, an electronic mapping system and, most recently, a work management system.

Customer growth requires significant capital outlays for new transmission and distribution plant. Necessary financing of continued construction has occurred during 2004. In July 2004, the Company issued $65 million in Clark County, Nevada Industrial Development Revenue Bonds ("IDRBs"). The net proceeds from the 5.25% tax-exempt bonds were used to finance construction expenditures in southern Nevada. The Company also issued 2.6 million shares of common stock through its various stock plans receiving $58.7 million in net proceeds in 2004. (See the section on **2004 Financing Activity** for additional information.)

The results of the natural gas operations segment and the overall results of the Company are heavily dependent upon the three components noted previously (general rate relief, weather, and customer growth). Significant changes in these components (primarily weather) have contributed to somewhat volatile earnings. Management continues to work 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.

To mitigate margin volatility due to weather and other usage variations, the California Public Utilities Commission ("CPUC") authorized a margin tracker in March 2004 that allows Southwest to record under or over-collected margin in a balancing account for recovery or refund to customers in a subsequent period. The margin recorded in the balancing account is based on the difference between billed and authorized levels. In August 2004, the Public Utilities Commission of Nevada ("PUCN") approved certain rate design improvements to mitigate weather variations. The monthly basic service charge was increased by $0.50 per residential customer and declining block rates were implemented. In December 2004, Southwest filed a general rate application with the Arizona Corporation Commission ("ACC") for its Arizona rate jurisdiction. The Company is asking the ACC to restructure residential rates to separate the recovery of fixed operating costs from the volume of gas it sells and has also proposed revising rates to shift a substantial portion of its fixed operating costs away from cold weather consumption. (See the section on **Rates and Regulatory Proceedings** for further discussion.)

Operating costs have been increasing primarily due to general increases in labor and maintenance costs and operating expenses associated with serving additional customers. Additional factors include higher insurance premiums, rising employee-related costs, and incremental costs to develop energy efficient technology. In 2005, operating costs will be negatively impacted by approximately $5 million for increased pension costs. (See **Application of Critical Accounting Policies** for more information.)

As of December 31, 2004, Southwest had 1,613,000 residential, commercial, industrial, and other natural gas customers, of which 890,000 customers were located in Arizona, 579,000 in Nevada, and 144,000 in California. Residential and commercial customers represented over 99 percent of the total customer base. During 2004, Southwest added a record 82,000 customers, a five percent increase, of which 39,000 customers were added in Arizona, 37,000 in Nevada, and 6,000 in California. These additions are largely attributed to population growth in the service areas. Based on current commitments from builders, customer growth, excluding acquisitions, is expected to be approximately five percent in 2005. During 2004, 54 percent of operating margin was earned in Arizona, 35 percent in Nevada, and 11 percent in California. During this same period, Southwest earned 86 percent of operating margin from residential and small commercial customers, 5 percent from other sales customers, and 9 percent from transportation customers. These general patterns are expected to continue.

Results of Natural Gas Operations

Year Ended December 31, (Thousands of dollars)	2004	2003	2002
Gas operating revenues	$1,262,052	$1,034,353	$1,115,900
Net cost of gas sold	645,766	482,503	563,379
Operating margin	616,286	551,850	552,521
Operations and maintenance expense	290,800	266,862	264,188
Depreciation and amortization	130,515	120,791	115,175
Taxes other than income taxes	37,669	35,910	34,565
Operating income	157,302	128,287	138,593
Other income (expense)	1,611	2,955	3,108
Net interest deductions	78,137	76,251	78,505
Net interest deductions on subordinated debentures	7,724	2,680	—
Preferred securities distributions	—	4,180	5,475
Income before income taxes	73,052	48,131	57,721
Income tax expense	24,698	13,920	18,493
Contribution to consolidated net income	$ 48,354	$ 34,211	$ 39,228

2004 vs. 2003

Contribution from natural gas operations increased $14.1 million in 2004 compared to 2003. The improvement was principally the result of higher operating margin partially offset by increased operating costs.

Operating margin increased $64 million in 2004 as compared to 2003. A record 82,000 customers were added during 2004, a growth rate of five percent. New customers contributed $21 million in incremental margin. A return to more normal temperatures in 2004 from the warm temperatures experienced in 2003 resulted in a $25 million increase in margin between years. Rate relief in California and Nevada provided $18 million.

Operations and maintenance expense increased $23.9 million, or nine percent, compared to 2003. The increase reflects general increases in labor and maintenance costs along with incremental operating expenses associated with serving additional customers. Additional factors included increases in insurance premiums, employee-related costs, and costs to develop energy efficient technology.

Depreciation expense and general taxes increased $11.5 million, or seven percent, as a result of construction activities. Average gas plant in service increased $249 million, or nine percent, as compared to 2003. The increase reflects ongoing capital expenditures for the upgrade of existing operating facilities and the expansion of the system to accommodate continued customer growth.

Net financing costs rose $2.8 million, or three percent, between years primarily due to an increase in average debt outstanding to help finance growth, partially offset by a reduction in interest costs associated with the purchased gas adjustment ("PGA") account balance.

During 2004, Southwest recognized $1.6 million of income tax benefits based on an analysis of current and deferred taxes following the completion of general rate cases and the closure of federal tax year 2000. In 2003, Southwest recognized $2 million of income tax benefits associated with plant-related items.

2003 vs. 2002

Contribution from natural gas operations declined $5 million in 2003 compared to 2002. The decrease was principally the result of lower operating margin and increased operating expenses, partially offset by decreased financing costs.

Operating margin decreased $671,000 in 2003 as compared to 2002. Approximately 67,000 customers were added during 2003, a growth rate of five percent. Another 9,000 customers were added in October 2003 with the acquisition of BMG. New customers contributed $16 million in incremental margin. Differences in heating demand caused by weather variations between years resulted in a $13 million margin decrease as warmer-than-normal temperatures were experienced during both years. During 2003, operating margin was negatively impacted $32 million by the weather, while in 2002 the negative impact was $19 million. Conservation, energy efficiency and other factors accounted for the remainder of the decline.

Operations and maintenance expense increased $2.7 million, or one percent, compared to 2002. The impacts of general cost increases and costs associated with the continued expansion and upgrading of the gas system to accommodate customer growth were offset by cost-curbing management initiatives begun in the fourth quarter of 2002.

Depreciation expense and general taxes increased $7 million, or five percent, as a result of construction activities. Average gas plant in service increased $231 million, or nine percent, as compared to 2002. The increase reflects ongoing capital expenditures for the upgrade of existing operating facilities and the expansion of the system to accommodate continued customer growth.

Net financing costs declined $869,000 between years primarily due to lower interest rates on variable-rate debt and interest savings generated from the refinancing of IDRBs and preferred securities instruments in 2003.

During 2003, Southwest recognized $2 million of income tax benefits associated with plant-related items. In 2002, Southwest recognized $2.7 million of income tax benefits associated with state taxes, plant, and non-plant related items.

Rates and Regulatory Proceedings

Arizona General Rate Case. In December 2004, Southwest filed a general rate application with the ACC for its Arizona rate jurisdiction. The application seeks authorization to increase operating revenues by $70.8 million. The request is a result of increases in fixed operating costs and a rate structure that has hindered Southwest's ability to earn the return authorized by the ACC. The Company is asking the ACC to restructure residential rates to separate the recovery of fixed operating costs from the volume of gas it sells and has also proposed revising rates to shift a portion of the recovery of its fixed operating costs away from cold weather consumption. Southwest also requested a margin-balancing account to mitigate margin volatility due to weather and other usage variations. Hearings are expected in the fourth quarter of 2005. Management cannot predict the amount or timing of rate relief ultimately granted. The last general rate increase received in Arizona was November 2001.

Nevada General Rate Cases. In March 2004, Southwest filed general rate applications with the PUCN, which included requests for annual increases of $8.6 million for northern Nevada and $18.9 million in southern Nevada. Southwest requested increased and seasonally adjusted basic service charges to recover fixed costs and a margin-balancing account to mitigate margin volatility due to weather and other usage variations. At hearings held in July 2004, the PUCN staff and the Bureau of Consumer Protection recommended that the total increase Southwest originally requested be reduced by one-third to two-thirds. The proposed reductions from filed amounts primarily related to differences in returns on common equity, capital structure and depreciation rates.

In August 2004, the PUCN approved annualized rate increases of $6.4 million for northern Nevada and $7.3 million in southern Nevada effective September 2004. The order did not include a margin balancing account, but certain rate design improvements to mitigate weather variations were approved by the PUCN. The monthly basic service charge was increased by $0.50 per residential customer and declining block rates were implemented. In addition, the PUCN ordered the Company to outline a plan to increase summer usage and file a weather normalization plan to address margin volatility issues with its next general rate case.

California General Rate Cases. In March 2004, the CPUC rendered a decision on the general rate cases filed by Southwest in February 2002 for its southern and northern California jurisdictions. The CPUC approved annualized rate increases of $3.6 million in southern California and $3.1 million in northern California, effective May 2003, plus attrition amounts as a result of inflation and safety-related activities beginning in 2004. The CPUC decision also includes attrition allowances through 2006. There were no gas cost disallowances in the CPUC decision.

The approved billing rates were put in place in mid-April 2004. In 2004, approximately $13 million in incremental operating margin was realized. Southwest was previously authorized by the CPUC to establish a memorandum account to track the impact of the delayed rate relief decision from May 2003 through the effective date of the general rate case. Approximately $3.3 million of the rate relief recorded during 2004 reflects the activity in the memorandum account for 2003.

To mitigate margin volatility due to weather and other usage variations, the CPUC authorized a margin tracker that allows Southwest to record under or over-collected margin in a balancing account for recovery or refund to customers in a subsequent period. The margin recorded in the balancing account is based on the difference between billed and authorized levels.

In November 2004, Southwest made its annual attrition filing, which was approved by the CPUC effective January 2005. The combined effect of the filing, which also adjusted various other balancing account surcharges, was an increase in annual margin of $2.8 million in southern California and $600,000 in northern California.

FERC Jurisdiction. In January 2005, Paiute filed a general rate case with the Federal Energy Regulatory Commission ("FERC"). The application seeks authorization to increase annual revenues by $1.7 million. The filing was a result of a FERC order issued in December 2004, whereby the Company entered into settlement agreements related to the purchase of a previously leased LNG peaking facility. New rates are expected to be implemented in the third quarter of 2005 (subject to refund until a final FERC decision is received). The last general rate increase received by Paiute was in January 1997. (See **Other Filings** section below for further discussion of the LNG facilities settlements.)

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

	2004	2003
Arizona	$15.3	$(5.8)
Northern Nevada	13.1	1.7
Southern Nevada	41.9	5.1
California	11.8	8.2
	$82.1	$ 9.2

Arizona PGA Filings. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits. In December 2004, the ACC approved the implementation of a temporary PGA surcharge of $0.02 per therm to pass through higher costs of purchased natural gas during the 2004-2005 winter heating season.

Nevada PGA Filings. In Nevada, tariffs provide for annual adjustment dates for changes in purchased gas costs. In addition, Southwest may request to adjust rates more often, if conditions warrant. As a result of increases in gas costs experienced since the annual filing in June 2003 (in addition to projected continued increases), an out-of-cycle filing was made in December 2003. In May 2004, the PUCN approved a $43.3 million annualized increase in southern Nevada and a $12.1 million increase in northern Nevada. The new rates became effective June 2004.

In June 2004, Southwest made its annual PGA filing with the PUCN requesting rate increases of $16.3 million for customers in southern Nevada and $2.6 million for customers in northern Nevada. To assist in the amortization of the forecasted under-collected PGA balance, the PUCN approved a $30.6 million annualized increase in southern Nevada and a $10.9 million annualized increase in northern Nevada effective December 2004.

In a separate action, the PUCN issued an order in October 2004 instructing Southwest to eliminate the PGA provisions in its tariff and instead account for gas costs as provided under the deferred energy provisions of the Nevada Administrative Code. These provisions result in little difference in the method used to account for or report purchased gas costs, including the ability of the Company to defer over or under-collections of gas costs to balancing accounts. Southwest filed comments with the PUCN during November to clarify the requirements. The changes become effective at the time Southwest makes its next purchased gas cost adjustment filing.

California Gas Cost Filings. In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized. Monthly adjustments are designed to provide a more timely recovery of gas costs and to send appropriate pricing signals to customers. As part of the general rate case decision, Southwest was encouraged by the CPUC to propose a Gas Cost Incentive Mechanism ("GCIM"). A GCIM is designed to provide greater incentive to reduce gas costs than exists under traditional regulation, encourage reasonable risk taking, and reduce administrative burden.

In November 2004, the Company filed for a GCIM using attributes similar to those used by other California utilities. The plan would provide for savings or penalties for gas cost incurred as compared to an established benchmark. The savings and/or penalties, neither of which are expected to be significant, would then be shared on an annual basis by ratepayers and shareholders based upon an authorized percentage. The CPUC Office of Ratepayer Advocates filed comments in support of the GCIM. Final approval of a GCIM is expected in mid 2005.

Other Filings

LNG Facilities. The Company leased a liquefied natural gas ("LNG") facility and approximately 61 miles of transmission main on its northern Nevada system under an agreement scheduled to expire in mid 2005. These storage and transmission facilities provide peaking capabilities during high demand months. Negotiations to purchase the facilities were begun several years ago and preparations were also being made to provide alternatives to the leased facilities to be in service by July 2005 in the event that a purchase agreement could not be consummated.

In May 2004, Paiute (an interstate pipeline subsidiary of Southwest Gas), filed an application with the FERC to abandon the leased facilities and to construct a compressor station to replace a portion of the transmission system capacity. Tuscarora Gas Transmission Company ("Tuscarora") also made a filing with the FERC proposing to expand its system to provide additional service to the customers whose LNG service was to be terminated.

In June 2004, the Company received a notice of default and demand for indemnification asserting that it was in default on the lease from Uzal, LLC ("Uzal"), the owner of the facilities. The Company responded to the notice of default certifying that no event of default existed and disputing the scope of the claims. In June 2004, Uzal filed suit in the United States District Court, District of Nevada, alleging breach of the lease and certain related agreements, tortious interference with contract, and tortious interference with prospective economic advantage. In July 2004, Uzal filed an application with the FERC seeking authorization to provide storage and transportation service from the LNG facilities.

In October 2004, the Company and Uzal reached an agreement, subject to regulatory approval, to resolve their dispute which allowed for the dismissal of the related litigation. In addition, Paiute agreed to purchase the LNG facilities and associated transmission main for approximately $22 million and continue to provide natural gas storage service in northern California and northern Nevada.

In addition to the Paiute-Uzal settlement, Paiute and Southwest were parties to a Joint Parties Settlement filed with the FERC. Other members of the Joint Parties Settlement included Avista, Public Service Resources Corporation, Sierra Pacific Power Company, Tuscarora, and Uzal. The Joint Parties Settlement was predicated upon Paiute's acquisition of the LNG facilities pursuant to the Paiute-Uzal settlement.

In December 2004, the FERC issued an order approving the Paiute-Uzal settlement and Joint Parties Settlement. The order resulted in the issuance of a Certificate of Public Convenience and Necessity to Paiute authorizing it to acquire and operate the LNG facilities and provided Paiute with the authority to provide long-term LNG storage services to its customers under new storage service agreements. As part of the settlement, Paiute withdrew its application related to the abandonment of the leased facilities and construction of a compressor station. In addition, Tuscarora withdrew its application to construct its proposed 2005 expansion project, and Uzal withdrew its application seeking authorization to provide storage and transportation service from the LNG facilities. The approval of the Joint Parties Settlement and the closing on the purchase of the LNG facilities in December 2004 completely resolved five pending, contested FERC proceedings, as well as two related court cases.

El Paso Transmission System. Since November 1999, the FERC has been examining capacity allocation issues on the El Paso system in several proceedings. This examination resulted in a series of orders by the FERC in which all of the major full requirements transportation service agreements on the El Paso system, including the agreement by which Southwest obtained the transportation of gas supplies to its Arizona service areas, were converted to contract demand-type service agreements, with fixed maximum service limits, effective September 2003. At that time, all of the transportation capacity on the system was allocated among the shippers. In order to help ensure that the converting full requirements shippers would have adequate capacity to meet their needs, El Paso was authorized to expand the capacity on its system by adding compression.

Since 2003, the FERC has reviewed issues related to the implementation of the full requirements conversion. Parties, including Southwest, filed petitions for judicial review of the FERC orders mandating the conversion. In December 2004, the United States Court of Appeals denied a petition seeking to reverse the prior FERC order that converted the agreements to contract demand. As a result, Southwest plans to pursue a reallocation of shipper costs at the United States Court of Appeals level based upon the contract demand quantities. However, Southwest believes it has adequate capacity to meet customer requirements, and no additional actions are anticipated on the capacity allocation issue.

Capital Resources and Liquidity

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. The capital requirements and resources of the construction services segment are not material to the overall capital requirements and resources of the Company.

Southwest continues to experience significant customer growth. This growth has required significant capital outlays for new transmission and distribution plant, to keep up with consumer demand. During the three-year period ended December 31, 2004, total gas plant increased from $2.6 billion to $3.3 billion, or at an annual rate of nine percent. Customer growth was the primary reason for the plant increase as Southwest added 216,000 net new customers during the three-year period.

During 2004, construction expenditures for the natural gas operations segment were $253 million (excluding the $22 million LNG facility purchase discussed below). Approximately 75 percent of these expenditures represented new construction and the balance represented costs associated with routine replacement of existing transmission, distribution, and general plant. Cash flows from operating activities of Southwest (net of dividends) provided $95 million of the required capital resources pertaining to total capital expenditures in 2004. The remainder was provided from external financing activities and existing credit facilities. Operating cash flows in 2004 were negatively impacted by natural gas prices as under-collected PGA balances at December 31, 2003 have increased from $9.2 million to $82.1 million at December 31, 2004. Southwest utilizes short-term borrowings to temporarily finance under-collected PGA balances.

Asset Purchases

In July 2004, the Company announced an agreement with Avista to purchase Avista's natural gas distribution properties in South Lake Tahoe, California. Avista serves approximately 18,000 customers in this region. The cash purchase price for the properties is $15 million, subject to closing adjustments. The agreement is also subject to customary closing conditions and regulatory review, including approval by the CPUC. Once approvals have been received, the properties will be integrated into the northern Nevada operations of Southwest, which include contiguous gas properties in the Lake Tahoe Basin. It is anticipated that Southwest will assume the rates in effect at the time of closing the purchase. The purchase price will be financed using existing credit facilities. The sale is expected to close in the second quarter of 2005.

The Company previously leased a LNG facility and approximately 61 miles of transmission main on its northern Nevada system. In December 2004, Paiute purchased the LNG facilities and associated transmission main for approximately $22 million, and continues to provide natural gas storage service in northern California and northern Nevada. The purchase price was financed with short-term debt and existing credit facilities.

2004 Financing Activity

In April 2004, the Company entered into a sales agency financing agreement with BNY Capital Markets, Inc. ("BNYCMI"). Of the $200 million in securities available at the time under the Company's shelf registration statement, the Company filed a prospectus supplement in May designating an aggregate $60 million as common stock to be issued in at-the-market offerings ("Equity Shelf Program") from time to time with BNYCMI acting as agent. During 2004, approximately 1.4 million shares were issued with gross proceeds of $34.1 million, agent commissions of $341,000, and net proceeds of $33.8 million. During the fourth quarter of 2004, approximately 558,000 shares were issued with gross proceeds of $14 million, agent commissions of $140,000, and net proceeds of $13.9 million.

During 2004, the Company issued approximately 1.2 million additional shares through its DRSPP, Employee Investment Plan, Management Incentive Plan, and Stock Incentive Plan. In August 2004, the Company registered 1 million additional shares of common stock with the Securities and Exchange Commission ("SEC") for issuance under the DRSPP.

At December 31, 2004, the Company had $166 million in securities available under a shelf registration statement for issuance including $25.9 million of common stock to be issued through the Equity Shelf Program discussed previously.

In July 2004, the Company issued $65 million in Clark County, Nevada IDRBs Series 2004A, due 2034. The net proceeds from the 5.25% tax-exempt bonds were used to finance construction and improvement of pipeline systems and facilities located in southern Nevada.

In September 2004, the Company remarketed the $20 million 3.35% 2003 Series D IDRBs, due 2038, at a rate of 5.25%. The original 3.35% interest rate was an 18-month rate which was required to be remarketed by September 2004.

In October 2004, the Company issued $75 million in Clark County, Nevada 5% Series 2004B Industrial Development Refunding Revenue Bonds ("IDRRBs"), due 2033. The Series 2004B IDRRBs were issued at a discount of 0.625%. The proceeds of the new

IDRRBs were used to refinance $75 million in 6.5% 1993 Series A IDRBs, due 2033. The redemption of the 1993 Series A IDRBs occurred on December 1, 2004 and included an early redemption premium of 1% ($750,000).

2005 Construction Expenditures and Financing

Southwest estimates construction expenditures during the three-year period ending December 31, 2007 will be approximately $700 million. Of this amount, approximately $270 million are expected to be incurred in 2005. During the three-year period, cash flow from operating activities (net of dividends) is estimated to fund approximately 80 percent of the gas operations' total construction expenditures, assuming timely recovery of currently deferred PGA balances. The Company expects to raise $75 million to $100 million from its various common stock programs. The remaining cash requirements are expected to be provided by other external financing sources. The timing, types, and amounts of these 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 service areas, and earnings. These external financings may include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

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. 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 customary leverage, net worth and other covenants, and securities ratings covenants that, if set in motion, would increase financing costs. To date, the Company has not incurred any increased financing costs as a result of these covenants.

Southwest has fixed-price gas purchase contracts, which are considered normal purchases occurring in the ordinary course of business. These gas purchase contracts are entered into annually to mitigate market price volatility. The Company does not currently utilize other stand-alone derivative instruments for speculative purposes or for hedging and does not have foreign currency exposure. Southwest is currently considering using stand-alone derivatives to hedge against possible price volatility. However, any such change would be communicated to Southwest's various regulatory commissions, and costs of such derivative financial instruments would be pursued as part of the PGA mechanisms for recovery from customers in each jurisdiction. None of the Company's long-term financial instruments or other contracts are derivatives that are marked to market, or contain embedded derivatives with significant mark-to-market value.

Contractual Obligations

Obligations under long-term debt, gas purchase obligations and non-cancelable operating leases at December 31, 2004 were as follows (millions of dollars):

	Payments Due By Period				
Contractual Obligations	Total	2005	2006-2007	2008-2009	Thereafter
Short-term debt (Note 7)	$ 100	$100	$ —	$ —	$ —
Subordinated debentures to Southwest Gas Capital II (Note 5)	103	—	—	—	103
Long-term debt (Note 6)	1,193	30	198	26	939
Operating leases (Note 2)	40	6	9	7	18
Gas purchase obligations (a)	398	311	87	—	—
Pipeline capacity (b)	482	69	136	124	153
Other commitments	12	7	5	—	—
Total	$2,328	$523	$435	$157	$1,213

(a) Includes fixed price and variable rate gas purchase contracts covering approximately 116 million dekatherms. Fixed price contracts range in price from $4.40 to $6.38 per dekatherm. Variable price contracts reflect minimum contractual obligations.

(b) Southwest has pipeline capacity contracts for firm transportation service, both on a short- and long-term basis, with several companies (primarily El Paso Natural Gas Company and Kern River Gas Transmission Company) for all of its service territories. 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.

Estimated pension funding for 2005 is $16.5 million.

The Company has an agreement with Avista to purchase Avista's natural gas distribution properties in South Lake Tahoe, California for $15 million which is expected to close in the second quarter of 2005.

Liquidity

Liquidity refers to the ability of an enterprise to generate adequate amounts of cash to meet its cash requirements. Several general factors that could significantly affect capital resources and liquidity in future years include inflation, growth in the economy, changes in income tax laws, changes in the ratemaking policies of regulatory commissions, interest rates, variability of natural gas prices, and the level of Company earnings.

The price of natural gas has varied widely over the past several years. Southwest customers have benefited from the fixed prices associated with term contracts in place during this period. These contracts are generally of short duration (less than one year) and cover about half of Southwest's supply needs. Southwest enters into new contracts annually to replace those that are expiring to help mitigate price volatility. Remaining needs will be covered with the purchase of natural gas on the spot market, which is subject to market fluctuations, in addition to the possible future use of stand-alone derivative instruments to hedge against potential price volatility. Over the next few years, continued strong growth in natural gas demand and limited supply increases indicate prices for natural gas will likely remain volatile. Southwest continues to pursue all available sources to maintain the balance between a low cost and reliable supply of natural gas for its customers. All incremental costs will be pursued as part of the PGA mechanisms for recovery from customers in each rate jurisdiction.

The rate schedules in Southwest's service territories contain PGA clauses which permit adjustments to rates as the cost of purchased gas changes. The PGA mechanism allows Southwest to change the gas cost component of the rates charged to its customers to reflect increases or decreases in the price expected to be paid to its suppliers and companies providing interstate pipeline transportation service.

On an interim basis, Southwest generally 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, 2004, the combined balances in PGA accounts totaled an under-collection of $82.1 million versus an under-collection of $9.2 million at December 31, 2003. See **PGA Filings** for more information on recent regulatory filings. Southwest utilizes short-term borrowings to temporarily finance under-collected PGA balances.

PGA changes affect cash flows but have no direct impact on profit margin. In addition, since Southwest is permitted to accrue interest on PGA balances, the cost of incremental, PGA-related short-term borrowings will be offset, and there should be no material negative impact to earnings. 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).

Effective May 2004, the Company obtained a new $250 million three-year credit facility of which *$150 million is for working* capital purposes (and related outstanding amounts will be designated as short-term debt). Interest rates for the new facility are calculated at either the London Interbank Offering Rate ("LIBOR") plus an applicable margin, or the greater of the prime rate or one-half of one percent plus the Federal Funds rate. The new facility replaced the former $250 million credit facility consisting of a $125 million three-year facility and a $125 million 364-day facility. The Company believes the $150 million designated for working capital purposes is adequate to meet anticipated liquidity needs ($55 million was available at December 31, 2004).

The Company has a common stock dividend policy which states that common stock dividends will be paid at a prudent level that is within the normal dividend payout range for its respective businesses, and that the dividend will be established at a level considered sustainable in order to minimize business risk and maintain a strong capital structure throughout all economic cycles. The quarterly common stock dividend was 20.5 cents per share throughout 2004. The dividend of 20.5 cents per share has been paid quarterly since September 1994.

Security 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., the better the rating, the lower the cost to borrow funds).

Since January 1997, Moody's Investors Service, Inc. ("Moody's") has rated Company unsecured long-term debt at Baa2. Moody's debt ratings range from Aaa (best quality) to C (lowest quality). Moody's applies a Baa2 rating to obligations which are considered medium grade obligations (i.e., they are neither highly protected nor poorly secured).

The Company's unsecured long-term debt rating from Fitch, Inc. ("Fitch") is BBB. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of BBB indicates a credit quality that is considered prudent for investment.

The Company's unsecured long-term debt rating from Standard and Poor's Ratings Services ("S&P") is BBB-. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of BBB- indicates 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.

Inflation

Results of operations are impacted by inflation. Natural gas, labor, and construction costs are the categories most significantly impacted by inflation. Changes to cost of gas are generally recovered through PGA mechanisms and do not significantly impact net earnings. Labor is a component 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.

Insurance Coverage

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 has been responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers would be responsible for amounts up to the policy limits. For the policy year August 2004 to July 2005, the self-insured retention amount associated with general liability claims increased from $1 million per incident to $1 million per incident plus payment of the first $10 million in aggregate claims above $1 million in the policy year. Management cannot predict the likelihood that any future claim will exceed $1 million. Therefore, the impact, if any, this policy change will have on the future results of operations or financial condition of the Company is not determinable.

Results of Construction Services

Year Ended December 31, (Thousands of dollars)	2004	2003	2002
Construction revenues	$215,008	$196,651	$205,009
Cost of construction	196,792	184,290	191,561
Gross profit	18,216	12,361	13,448
General and administrative expenses	5,742	5,543	5,542
Operating income	12,474	6,818	7,906
Other income (expense)	2,131	1,290	1,221
Interest expense	645	855	1,466
Income before income taxes	13,960	7,253	7,661
Income tax expense	5,539	2,962	2,924
Contribution to consolidated net income	$ 8,421	$ 4,291	$ 4,737

2004 vs. 2003

The 2004 contribution to consolidated net income from construction services increased $4.1 million from the prior year. The increase was primarily due to overall revenue growth, coupled with an improvement in the number of profitable bid jobs, and a favorable equipment resale market in the current year. The improvement between years also reflects the impact of an unfavorable settlement of a $1.3 million insurance claim in 2003.

Revenues and gross profit for 2004 reflect an increased workload under existing contracts and an increase in the quantity and profitability of bid work. Favorable working conditions in several operating areas facilitated additional construction activity. The construction revenues above include NPL contracts with Southwest totaling $61.6 million in 2004, $58.9 million in 2003, and $70.4 million in 2002. NPL accounts for the services provided to Southwest at contractual (market) prices.

The convergence of favorable factors that resulted in the increase in contribution from construction services is not expected to be repeated in the near future. The amount of work received under existing blanket contracts, the amount and profitability of bid work, and the equipment resale market vary from year to year.

2003 vs. 2002

The 2003 contribution to consolidated net income from construction services decreased $446,000 from the prior year. The decrease was primarily due to a decline in construction revenues and an insurance settlement, partially offset by lower interest expense.

Revenues decreased $8.4 million due to a reduced workload in some operating areas, the completion of certain projects, and the non-renewal of two long-term contracts. Cost of construction includes a one-time $1.3 million charge for an unfavorable insurance settlement. Interest expense declined $611,000 as a result of the refinancing of long-term debt to take advantage of lower interest rates.

Recently Issued Accounting Pronouncements

In November 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 151, "Inventory Costs." SFAS No. 151 is an amendment of Accounting Research Bulletin ("ARB") No. 43, "Restatement and Revision of Accounting Research Bulletins." SFAS No. 151 addresses the accounting for abnormal amounts of idle facility expense, freight handling costs and spoilage and will no longer allow companies to capitalize such inventory costs on their balance sheets when the production defect rate varies significantly from the expected rate. The provisions of SFAS No. 151 are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets." SFAS No. 153 is an amendment of Accounting Principles Board Opinion ("APB") No. 29, "Accounting for Nonmonetary Transactions." SFAS No. 153 addresses the accounting for exchanges of similar productive assets and eliminates the exception to the fair-value principle for such exchanges, which previously had been accounted for based on the book value of the asset surrendered with no gain recognition. Under SFAS No. 153, using certain criteria, the gain would be recognized currently and not deferred. The provisions of SFAS No. 153 are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Management has not yet quantified the potential effects of the new standard on the financial position or results of operations of the Company.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment." SFAS No. 123 (revised 2004) is a revision of SFAS 123, "Accounting for Stock Based Compensation" and supersedes APB No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123 (revised 2004) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This statement eliminates the alternative to use APB No. 25 and the intrinsic value method of accounting. SFAS No 123 (revised 2004) requires entities to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant-date fair value of those awards (with limited exceptions). The provisions of SFAS No. 123 (revised 2004) are effective for Southwest as of the beginning of the first interim reporting period beginning after June 15, 2005. At December 31, 2004, the Company had two stock-based compensation plans. These plans are currently accounted for in accordance with APB Opinion No. 25 "Accounting for Stock Issued to Employees." In connection with the stock-based compensation plans, the Company recognized compensation expense of $3 million in 2004, $4.1 million in 2003, and $3 million in 2002. Compensation expense will increase due to the adoption of SFAS No. 123 (revised 2004) since no compensation expense is currently recorded for the Company's Stock Incentive Plan. For more information regarding the effect the original SFAS 123 would have had on historical results of operations, see **Note 1 – Summary of Significant Accounting Policies,** *Stock-Based Compensation.* The Company expects a similar impact to its results of operations upon the adoption of SFAS 123 (revised 2004).

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 examples of accounting policies that are 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.**

- 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 enterprises (including SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation") 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). Refer to **Note 4 — Regulatory Assets and Liabilities** for a list of regulatory assets.

- 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, revenues for natural gas that has been delivered but not yet billed are accrued. This unbilled revenue is estimated each month based on daily sales volumes, applicable rates, analyses reflecting significant historical trends, weather, and experience. In periods of extreme weather conditions, the interplay of these assumptions could impact the variability of the unbilled revenue estimates.

- The income tax calculations of the Company require estimates due to regulatory differences between the multiple states in which the Company operates, and future tax rate changes. 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 Company regularly assesses financial statement tax provisions and adjusts the tax provisions when necessary as additional information is obtained. A change in the regulatory treatment or significant changes in tax-related estimates, assumptions, or enacted tax rates could have a material impact on the financial position and results of operations of the Company.

- *In accordance with approved regulatory practices, the depreciation expense for Southwest includes a component to recover* removal costs associated with utility plant retirements. In accordance with the SEC's position on presentation of these amounts, management has reclassified $84 million and $68 million as of December 31, 2004 and 2003, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs (in the liabilities section of the balance sheet).

  Under utility accounting, all plant is assumed to be fully depreciated upon retirement. However, retirements often occur earlier than the average service life of the plant group. Accumulated depreciation has an historical mix of credits (depreciation amounts designed to recover plant investment and net removal costs) and debits (charges for retirements and actual costs of removal). The actual amount of net removal costs recorded as credits has never been tracked by the Company. The estimate of the calculated cost of removal embedded in accumulated depreciation employed various assumptions including average service lives and historical depreciation rates. Variations in the assumptions utilized would result in a range of accumulated removal costs that would vary significantly from the amount estimated above.

- 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 costs for these plans are affected by the amount 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 of 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.

  Due to a decline in market interest rates for high-quality fixed income investments, the Company lowered the discount rate to 6.00% at December 31, 2004, from 6.5% at December 31, 2003. This change will result in a $5 million increase in pension expense for 2005. The reduction in the discount rate resulted in the accumulated benefit obligations of the retirement plan and the supplemental retirement plan exceeding the related plan assets at the measurement date of December 31, 2004. In accordance with generally accepted accounting standards, the Company's balance sheet includes an additional minimum pension liability of $17.4 million, with a corresponding accumulated other comprehensive loss, net of tax, recognized in stockholders' equity. Should interest rates rise in 2005, the accumulated other comprehensive loss could be reduced or eliminated and pension cost be reduced. Conversely, declining interest rates would put upward pressure on pension expense and cause the other comprehensive loss to increase.

  See **Note 9 – Employee Benefits** for plan assumptions and further discussion.

Management believes that regulation and the effects of regulatory accounting have the most significant impact on the financial statements. When Southwest files rate cases, capital assets, costs, and gas purchasing practices are subject to review, and disallowances can occur. Regulatory disallowances in the past have not been frequent but have on occasion been significant to the operating results of the Company.

Certifications

The 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, 2004 were included as exhibits to the 2004 Annual Report on Form 10-K which was filed with the SEC. The Company is also required to file an annual CEO certification regarding corporate governance listing standards compliance with the New York Stock Exchange ("NYSE"). The CEO certification, dated June 1, 2004, was filed with the NYSE in June 2004.

Forward-Looking Statements

This annual report contains statements which constitute "forward-looking statements" within the meaning of the 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, projections, strategies, future events or performance, and underlying assumptions. The words "may," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "continue," and similar words and expressions are generally used and intended to identify 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, the impact of weather variations on customer usage, customer growth rates, changes in natural gas prices, our ability to recover costs through our PGA mechanism, 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, future liability claims, changes in pipeline capacity for the transportation of gas and related costs, acquisitions and management's plans related thereto, competition and our ability to raise capital in external financings or through our DRSPP. In addition, the Company can provide no assurance that its discussions regarding certain trends relating to its financing, operations and maintenance expenses will continue in future periods. For additional information on the risks associated with the Company's business, see **Item 1. Business – Company Risk Factors** in the Company's Annual Report on Form 10-K for the year ended December 31, 2004.

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

	2004		2003		Dividends Paid	
	High	Low	High	Low	2004	2003
First quarter	$24.05	$22.39	$23.64	$19.30	$0.205	$0.205
Second quarter	24.20	21.50	22.45	19.74	0.205	0.205
Third quarter	24.46	22.70	23.49	20.14	0.205	0.205
Fourth quarter	26.15	23.45	23.48	22.04	0.205	0.205
					$0.820	$0.820

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At March 1, 2005, there were 24,174 holders of record of common stock and the market price of the common stock was $25.29.

Southwest Gas Corporation
Consolidated Balance Sheets

December 31, (Thousands of dollars, except par value)	2004	2003
Assets		
Utility plant:		
Gas plant	$3,287,591	$3,035,969
Less: accumulated depreciation	(985,919)	(896,309)
Acquisition adjustments, net	2,353	2,533
Construction work in progress	31,967	33,543
Net utility plant (Note 2)	2,335,992	2,175,736
Other property and investments	99,879	87,443
Current assets:		
Cash and cash equivalents	13,641	17,183
Accounts receivable, net of allowances (Note 3)	176,090	126,783
Accrued utility revenue	68,200	66,700
Deferred income taxes (Note 10)	—	6,914
Deferred purchased gas costs (Note 4)	82,076	9,151
Prepaids and other current assets (Note 4)	91,986	54,356
Total current assets	431,993	281,087
Deferred charges and other assets (Note 4)	70,252	63,840
Total assets	$2,938,116	$2,608,106

Southwest Gas Corporation
Consolidated Balance Sheets – (continued)

December 31, (Thousands of dollars, except par value)	2004	2003
Capitalization and Liabilities		
Capitalization:		
Common stock, $1 par (authorized - 45,000,000 shares; issued and outstanding – 36,794,343 and 34,232,098 shares)	$ 38,424	$ 35,862
Additional paid-in capital	566,646	510,521
Accumulated other comprehensive income (loss), net (Note 9)	(10,892)	–
Retained earnings	111,498	84,084
Total equity	705,676	630,467
Subordinated debentures due to Southwest Gas Capital II (Note 5)	100,000	100,000
Long-term debt, less current maturities (Note 6)	1,162,936	1,121,164
Total capitalization	1,968,612	1,851,631
Commitments and contingencies (Note 8)		
Current liabilities:		
Current maturities of long-term debt (Note 6)	29,821	6,435
Short-term debt (Note 7)	100,000	52,000
Accounts payable	165,872	110,114
Customer deposits	50,194	44,290
Accrued general taxes	38,189	32,466
Accrued interest	22,425	19,665
Deferred income taxes (Note 10)	26,676	–
Other current liabilities	49,854	45,442
Total current liabilities	483,031	310,412
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 10)	281,743	277,332
Taxes payable	3,965	6,661
Accumulated removal costs (Note 4)	84,000	68,000
Other deferred credits (Note 4)	116,765	94,070
Total deferred income taxes and other credits	486,473	446,063
Total capitalization and liabilities	$2,938,116	$2,608,106

The accompanying notes are an integral part of these statements.

Southwest Gas Corporation
Consolidated Statements of Income

Year Ended December 31, (In thousands, except per share amounts)	2004	2003	2002
Operating revenues:			
Gas operating revenues	$1,262,052	$1,034,353	$1,115,900
Construction revenues	215,008	196,651	205,009
Total operating revenues	1,477,060	1,231,004	1,320,909
Operating expenses:			
Net cost of gas sold	645,766	482,503	563,379
Operations and maintenance	290,800	266,862	264,188
Depreciation and amortization	146,018	136,439	130,210
Taxes other than income taxes	37,669	35,910	34,565
Construction expenses	187,040	174,185	182,068
Total operating expenses	1,307,293	1,095,899	1,174,410
Operating income	169,767	135,105	146,499
Other income and (expenses):			
Net interest deductions	(78,782)	(77,106)	(79,971)
Net interest deductions on subordinated debentures (Note 5)	(7,724)	(2,680)	—
Preferred securities distributions (Note 5)	—	(4,180)	(5,475)
Other income (deductions)	3,751	4,245	4,329
Total other income and (expenses)	(82,755)	(79,721)	(81,117)
Income before income taxes	87,012	55,384	65,382
Income tax expense (Note 10)	30,237	16,882	21,417
Net income	$ 56,775	$ 38,502	$ 43,965
Basic earnings per share (Note 12)	$ 1.61	$ 1.14	$ 1.33
Diluted earnings per share (Note 12)	$ 1.60	$ 1.13	$ 1.32
Average number of common shares outstanding	35,204	33,760	32,953
Average shares outstanding (assuming dilution)	35,488	34,041	33,233

The accompanying notes are an integral part of these statements.

Southwest Gas Corporation
Consolidated Statements of Cash Flows

Year Ended December 31, (Thousands of dollars)	2004	2003	2002
Cash Flow from Operating Activities:			
Net income	$ 56,775	$ 38,502	$ 43,965
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	146,018	136,439	130,210
Deferred income taxes	38,001	44,144	(15,684)
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	(49,307)	4,416	24,687
Accrued utility revenue	(1,500)	(1,627)	(1,300)
Deferred purchased gas costs	(72,925)	(35,981)	110,219
Accounts payable	55,758	21,586	(20,858)
Accrued taxes	3,027	(386)	33,997
Other current assets and liabilities	(25,406)	1,692	4,763
Other	1,050	(1,009)	(11,525)
Net cash provided by operating activities	151,491	207,776	298,474
Cash Flow from Investing Activities:			
Construction expenditures and property additions	(302,688)	(240,671)	(282,851)
Other (Note 14)	6,106	(18,215)	23,985
Net cash used in investing activities	(296,582)	(258,886)	(258,866)
Cash Flow from Financing Activities:			
Issuance of common stock, net	58,687	21,290	18,174
Dividends paid	(28,836)	(27,685)	(27,009)
Issuance of subordinated debentures, net	—	96,312	—
Issuance of long-term debt, net	147,135	159,997	206,161
Retirement of long-term debt, net	(83,437)	(140,013)	(210,028)
Retirement of preferred securities	—	(60,000)	—
Change in short-term debt	48,000	(1,000)	(40,000)
Net cash provided by (used in) financing activities	141,549	48,901	(52,702)
Change in cash and cash equivalents	(3,542)	(2,209)	(13,094)
Cash at beginning of period	17,183	19,392	32,486
Cash at end of period	$ 13,641	$ 17,183	$ 19,392
Supplemental information:			
Interest paid, net of amounts capitalized	$ 80,433	$ 78,561	$ 76,867
Income taxes paid (received), net	$ (12,640)	$ (26,733)	$ 1,797

The accompanying notes are an integral part of these statements.

Southwest Gas Corporation
Consolidated Statements of Stockholders' Equity

(In thousands, except per share amounts)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
December 31, 2001	32,493	$34,123	$470,410	$ —	$ 56,667	$561,200
Common stock issuances	796	796	17,378			18,174
Net income					43,965	43,965
Dividends declared						
Common: $0.82 per share					(27,172)	(27,172)
December 31, 2002	33,289	34,919	487,788	—	73,460	596,167
Common stock issuances	943	943	20,347			21,290
Net income					38,502	38,502
Other			2,386			2,386
Dividends declared						
Common: $0.82 per share					(27,878)	(27,878)
December 31, 2003	34,232	35,862	510,521	—	84,084	630,467
Common stock issuances	2,562	2,562	56,125			58,687
Net income					56,775	56,775
Additional minimum pension liability adjustment, net of $6.5 million of tax (Note 9)				(10,892)		(10,892)
Comprehensive income						45,883
Dividends declared						
Common: $0.82 per share					(29,361)	(29,361)
December 31, 2004	36,794*	$38,424	$566,646	$(10,892)	$111,498	$705,676

* At December 31, 2004, 1.1 million common shares were registered and available for issuance under provisions of the Employee Investment Plan and the Dividend Reinvestment and Stock Purchase Plan. In addition, 2.3 million common shares are registered for issuance upon the exercise of options granted or to be granted under the Stock Incentive Plan (see Note 9). At December 31, 2004, $25.9 million in aggregate share value of the $60 million Equity Shelf Program remain available for issuance. During 2004, approximately 1.4 million shares were issued in at-the-market offerings through the Equity Shelf Program with gross proceeds of $34.1 million, agent commissions of $341,000, and net proceeds of $33.8 million. During the fourth quarter of 2004, approximately 558,000 shares were issued in at-the-market offerings through the Equity Shelf Program with gross proceeds of $14 million, agent commissions of $140,000, and net proceeds of $13.9 million.

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1 – Summary of Significant Accounting Policies

Nature of Operations. Southwest Gas Corporation (the "Company") is comprised of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest purchases, transports, and distributes natural gas to customers in portions of Arizona, Nevada, and California. The 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 sales are seasonal, peaking during the winter months. Variability in weather from normal temperatures can materially impact results of operations. Natural gas purchases and the timing of related recoveries can materially impact liquidity. Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Basis of Presentation. The Company follows generally accepted accounting principles ("GAAP") in accounting for all of its businesses. Accounting for the natural gas utility operations conforms with GAAP as applied to regulated companies and as prescribed by federal agencies and the commissions of the various states in which the utility operates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities 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, except for Southwest Gas Capital II (see Note 5). All significant intercompany balances and transactions have been eliminated with the exception of transactions between Southwest and NPL in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation."

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.

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 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.

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.

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. Southwest also recognizes accrued utility revenues for the estimated amount of services rendered between the meter-reading dates in a particular month and the end of such month.

Construction Revenues. The majority of the 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 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.

Asset Retirement Obligations. In accordance with approved regulatory practices, the depreciation expense for Southwest includes 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 $84 million and $68 million, as of December 31, 2004 and 2003, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs (in the liabilities section of the balance sheet).

Under utility accounting, all plant is assumed to be fully depreciated upon retirement. However, retirements often occur earlier than the average service life of the plant group. Accumulated depreciation has an historical mix of credits (depreciation amounts designed to recover plant investment and net removal costs) and debits (charges for retirements and actual costs of removal). The actual amount of net removal costs recorded as credits has never been tracked by the Company. The estimate of the calculated cost of removal embedded in accumulated depreciation employed various assumptions including average service lives and historical depreciation rates. Variations in the assumptions utilized would result in a range of accumulated removal costs that would vary significantly from the amount estimated above.

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 salvage value, removal costs, 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. Acquisition adjustments are amortized, as ordered by regulators, over periods which approximate the remaining estimated life of the acquired properties. Costs related to refunding utility debt and debt issuance expenses are deferred and amortized over the weighted-average lives of the new issues. Other regulatory assets, when appropriate, are amortized 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.

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 Company capitalized $808,000 in 2004, $2.6 million in 2003, and $3.1 million in 2002 of AFUDC related to natural gas utility operations. 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. The debt portion of AFUDC was $691,000, $1.5 million and $1.9 million for 2004, 2003 and 2002, respectively. 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.

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 and performance shares). 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)	2004	2003	2002
Average basic shares	35,204	33,760	32,953
Effect of dilutive securities:			
Stock options	111	73	94
Performance shares	173	208	186
Average diluted shares	35,488	34,041	33,233

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a maturity of three months or less, but exclude funds held in trust from the issuance of industrial development revenue bonds ("IDRBs").

Reclassifications. Certain reclassifications have been made to the prior year's financial information to present it on a basis comparable with the current year's presentation.

Recently Issued Accounting Pronouncements. In November 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 151, "Inventory Costs." SFAS No. 151 is an amendment of Accounting Research Bulletin ("ARB") No. 43, "Restatement and Revision of Accounting Research Bulletins." SFAS No. 151 addresses the accounting for abnormal amounts of idle facility expense, freight handling costs and spoilage and will no longer allow companies to capitalize such inventory costs on their balance sheets when the production defect rate varies significantly from the expected rate. The provisions of SFAS No. 151 are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets." SFAS No. 153 is an amendment of Accounting Principles Board Opinion ("APB") No. 29, "Accounting for Nonmonetary Transactions." SFAS No. 153 addresses the accounting for exchanges of similar productive assets and eliminates the exception to the fair-value principle for such exchanges, which previously had been accounted for based on the book value of the asset surrendered with no gain recognition. Under SFAS No. 153, using certain criteria, the gain would be recognized currently and not deferred. The provisions of SFAS No. 153 are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Management has not yet quantified the potential effects of the new standard on the financial position or results of operations of the Company.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment." SFAS No. 123 (revised 2004) is a revision of SFAS 123, "Accounting for Stock Based Compensation" and supersedes APB No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123 (revised 2004) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This statement eliminates the alternative to use APB No. 25 and the intrinsic value method of accounting. SFAS No 123 (revised 2004) requires entities to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant-date fair value of those awards (with limited exceptions). The provisions of SFAS No. 123 (revised 2004) are effective for Southwest as of the beginning of the first interim reporting period beginning after June 15, 2005. At December 31, 2004, the Company had two stock-based compensation plans. These plans are currently accounted for in accordance with APB Opinion No. 25 "Accounting for Stock Issued to Employees." In connection with the stock-based compensation plans, the Company recognized compensation expense of $3 million in 2004, $4.1 million in 2003, and $3 million in 2002. In 2005, compensation expense will increase due to the adoption of SFAS No. 123 (revised 2004) since no compensation expense is currently recorded for the Company's Stock Incentive Plan. The table below illustrates the effect SFAS 123 would have had on historical net income and earnings per share. The Company expects a similar impact to its results of operations upon the adoption of SFAS 123 (revised 2004).

Stock-Based Compensation. At December 31, 2004, the Company had two stock-based compensation plans, which are described more fully in **Note 9 – Employee Benefits.** These plans are currently accounted for in accordance with APB No. 25. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provision of SFAS No. 123 to its stock-based employee compensation (thousands of dollars, except per share amounts):

	2004	2003	2002
Net income, as reported	$56,775	$38,502	$43,965
Add: Stock-based employee compensation expense included in reported net income, net of related tax benefits	1,825	2,438	1,783
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefits	(1,958)	(2,920)	(2,024)
Pro forma net income	$56,642	$38,020	$43,724
Earnings per share:			
Basic – as reported	$ 1.61	$ 1.14	$ 1.33
Basic – pro forma	1.61	1.13	1.33
Diluted – as reported	1.60	1.13	1.32
Diluted – pro forma	1.60	1.12	1.32

Note 2 – Utility Plant

Net utility plant as of December 31, 2004 and 2003 was as follows (thousands of dollars):

December 31,	2004	2003
Gas plant:		
Storage	$ 17,189	$ 4,158
Transmission	233,841	215,907
Distribution	2,706,089	2,496,708
General	206,837	197,693
Other	123,635	121,503
	3,287,591	3,035,969
Less: accumulated depreciation	(985,919)	(896,309)
Acquisition adjustments, net	2,353	2,533
Construction work in progress	31,967	33,543
Net utility plant	$2,335,992	$2,175,736

Depreciation and amortization expense on gas plant was $128 million in 2004, $118 million in 2003, and $113 million in 2002.

Leases and Rentals. Southwest leases a portion of its corporate headquarters office complex in Las Vegas, and its administrative offices in Phoenix. The leases provide for current terms which expire in 2017 and 2009, respectively, with optional renewal terms available at the expiration dates. The rental payments for the corporate headquarters office complex are $2 million in each of the years 2005 through 2009 and $16.3 million cumulatively thereafter. The rental payments for the Phoenix administrative offices are $1.5 million for each of the years 2005 through 2008, and $1 million in 2009 when the lease expires. 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 treated as such for regulatory purposes. Rentals included in operating expenses for all operating leases were $20.3 million in 2004, $20 million in 2003, and $26.5 million in 2002. These amounts include NPL lease expenses of approximately $9.8 million in 2004, $9.6 million in 2003, and $12.3 million in 2002 for various short-term leases of equipment and temporary office sites.

The Company previously leased a LNG facility and approximately 61 miles of transmission main on its northern Nevada system. In December 2004, Paiute, a wholly owned interstate pipeline subsidiary of the Company, purchased the LNG facilities and associated transmission main.

The following is a schedule of future minimum lease payments for noncancellable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2004 (thousands of dollars):

Year Ending December 31,	
2005	$ 5,573
2006	4,977
2007	4,297
2008	4,011
2009	3,330
Thereafter	17,450
Total minimum lease payments	$39,638

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. At December 31, 2004, the gas utility customer accounts receivable balance was $148 million. Approximately 55 percent of the gas utility customers were in Arizona, 36 percent in Nevada, and 9 percent in California. 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. Provisions for uncollectible accounts are recorded monthly, as needed, and are included in the ratemaking process as a cost of service. Activity in the allowance for uncollectibles is summarized as follows (thousands of dollars):

	Allowance for Uncollectibles
Balance, December 31, 2001	$ 1,871
Additions charged to expense	3,824
Accounts written off, less recoveries	(3,870)
Balance, December 31, 2002	1,825
Additions charged to expense	2,523
Accounts written off, less recoveries	(2,102)
Balance, December 31, 2003	2,246
Additions charged to expense	2,586
Accounts written off, less recoveries	(2,860)
Balance, December 31, 2004	$ 1,972

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"). Company accounting policies conform to generally accepted accounting principles applicable to rate-regulated enterprises, principally SFAS No. 71, and reflect the effects of the ratemaking process. SFAS No. 71 allows for the deferral as regulatory assets, costs that otherwise would be expensed if it is probable 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.

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

December 31,	2004	2003
Regulatory assets:		
Deferred purchased gas costs	$ 82,076	$ 9,151
Accrued purchased gas costs *	35,600	8,800
SFAS No. 109 – income taxes, net	3,074	3,700
Unamortized premium on reacquired debt	19,229	18,560
Other	28,655	28,095
	168,634	68,306
Regulatory liabilities:		
Accumulated removal costs	(84,000)	(68,000)
Other	(730)	(425)
Net regulatory assets (liabilities)	$ 83,904	$ (119)

* Included in Prepaids and other current assets on the Consolidated Balance Sheet.

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

Note 5 – Preferred Securities and Subordinated Debentures

In October 1995, Southwest Gas Capital I (the "Trust"), a consolidated wholly owned subsidiary of the Company, issued $60 million of 9.125% Trust Originated Preferred Securities (the "Preferred Securities"). In connection with the Trust issuance of the Preferred Securities and the related purchase by the Company of all of the trust common securities, the Company issued to the Trust $61.8 million principal amount of its 9.125% Subordinated Deferrable Interest Notes, due 2025.

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, due 2043 ("Subordinated Debentures") to Trust II. The sole assets of Trust II are and will be the Subordinated Debentures. The interest and other payment dates on the Subordinated Debentures correspond to the distribution and other payment dates on the Preferred Trust Securities and Common Securities. Under certain circumstances, the Subordinated Debentures may be distributed to the holders of the Preferred Trust Securities and holders of the Common Securities in liquidation of Trust II. The Subordinated Debentures are redeemable at the option of the Company after August 2008 at a redemption price of $25 per Subordinated Debenture plus accrued and unpaid interest. In the event that the Subordinated Debentures are repaid, the Preferred Trust Securities and the Common Securities will be redeemed on a pro rata basis at $25 (par value) per Preferred Trust Security and Common Security plus accumulated and unpaid distributions. Company obligations under the Subordinated Debentures, the Trust Agreement (the agreement under which Trust II was formed), the guarantee of payment of certain distributions, redemption payments and liquidation payments with respect to the Preferred Trust Securities to the extent Trust II has funds available therefore and the indenture governing the Subordinated Debentures, including the Company agreement pursuant to such indenture to pay all fees and expenses of Trust II, other than with respect to the Preferred Trust Securities and Common Securities, taken together, constitute a full and unconditional guarantee on a subordinated basis by the Company of payments due on the Preferred Trust Securities. As of December 31, 2004, 4.1 million Preferred Trust Securities were outstanding.

The Company has the right to defer payments of interest on the Subordinated Debentures by extending the interest payment period at any time for up to 20 consecutive quarters (each, an "Extension Period"). If interest payments are so deferred, distributions to Preferred Trust Securities holders will also be deferred. During such Extension Period, distributions will continue to accrue with interest thereon (to the extent permitted by applicable law) at an annual rate of 7.70% per annum compounded quarterly. There could be multiple Extension Periods of varying lengths throughout the term of the Subordinated Debentures. If the Company exercises the right to extend an interest payment period, the Company shall not during such Extension Period (i) declare or pay dividends on, or make a distribution with respect to, or redeem, purchase or acquire or make a liquidation payment with respect to, any of its capital stock, or (ii) make any payment of interest, principal, or premium, if any, on or repay, repurchase, or redeem any debt securities issued by the Company that rank equal with or junior to the Subordinated Debentures; provided, however, that restriction (i) above does not apply to any stock dividends paid by the Company where the dividend stock is the same as that on which the dividend is being paid. The Company has no present intention of exercising its right to extend the interest payment period on the Subordinated Debentures.

A portion of the net proceeds from the issuance of the Preferred Trust Securities was used to complete the redemption of the 9.125% Trust Originated Preferred Securities effective September 2003 at a redemption price of $25 per Preferred Security, totaling $60 million plus accrued interest of $1.3 million.

In January 2003, the FASB issued Interpretation No. 46 "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" ("FIN 46") effective July 2003. This Interpretation of Accounting Research Bulletin No. 51 "Consolidated Financial Statements," addresses consolidation by business enterprises of variable interest entities. FIN 46 explains how to identify variable interest entities and how an enterprise assesses its interests in a variable interest entity to decide whether to consolidate that entity. Trust II, the issuer of the preferred trust securities, meets the definition of a variable interest entity.

Although the Company owns 100 percent of the common voting securities of Trust II, under FIN 46, the Company is not considered the primary beneficiary of this trust and therefore Trust II is not consolidated. The adoption of FIN 46 results in the Company reflecting a liability to Trust II (which under the prior accounting treatment would have been eliminated in consolidation) instead of to the holders of the preferred trust securities. As a result, payments and amortizations associated with the liability are classified on the consolidated statements of income as Net interest deductions on subordinated debentures. The preferred securities distributions category contains carrying costs of the original Preferred Securities. The $103.1 million Subordinated Debentures are shown on the balance sheet of the Company net of the $3.1 million Common Securities as Subordinated debentures due to Southwest Gas Capital II.

Note 6 – Long-Term Debt

December 31, (Thousands of dollars)	2004 Carrying Amount	2004 Market Value	2003 Carrying Amount	2003 Market Value
Debentures:				
7 1/2% Series, due 2006	$ 75,000	$ 79,523	$ 75,000	$ 83,149
Notes, 8.375%, due 2011	200,000	239,800	200,000	241,155
Notes, 7.625%, due 2012	200,000	234,500	200,000	232,198
8% Series, due 2026	75,000	92,858	75,000	88,240
Medium-term notes, 7.75% series, due 2005	25,000	25,840	25,000	27,198
Medium-term notes, 6.89% series, due 2007	17,500	18,848	17,500	19,443
Medium-term notes, 6.27% series, due 2008	25,000	26,830	25,000	27,219
Medium-term notes, 7.59% series, due 2017	25,000	30,050	25,000	29,217
Medium-term notes, 7.78% series, due 2022	25,000	30,663	25,000	29,076
Medium-term notes, 7.92% series, due 2027	25,000	30,790	25,000	29,220
Medium-term notes, 6.76% series, due 2027	7,500	8,175	7,500	7,725
Unamortized discount	(5,330)	–	(5,957)	–
	694,670		694,043	
Revolving credit facility and commercial paper	100,000	100,000	100,000	100,000
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
2003 Series B, due 2038	50,000	50,000	50,000	50,000
Fixed-rate bonds:				
6.50% 1993 Series A, due 2033	–	–	75,000	76,500
6.10% 1999 Series A, due 2038	12,410	14,023	12,410	12,596
5.95% 1999 Series C, due 2038	14,320	15,895	14,320	15,811
5.55% 1999 Series D, due 2038	8,270	8,725	8,270	9,014
5.45% 2003 Series C, due 2038	30,000	31,350	30,000	32,826
5.25% / 3.35% 2003 Series D, due 2038	20,000	20,776	20,000	20,000
5.80% 2003 Series E, due 2038	15,000	15,975	15,000	16,809
5.25% 2004 Series A, due 2034	65,000	66,625	–	–
5.00% 2004 Series B, due 2033	75,000	76,125	–	–
Unamortized discount	(2,918)	–	(1,986)	–
	387,082		323,014	
Other	11,005	–	10,542	–
	1,192,757		1,127,599	
Less: current maturities	(29,821)		(6,435)	
Long-term debt, less current maturities	$1,162,936		$1,121,164	

In May 2004, the Company obtained a new $250 million three-year credit facility of which $150 million is for working capital purposes (and related outstanding amounts are designated as short-term debt). Interest rates for the new facility are calculated at either the London Interbank Offering Rate ("LIBOR") plus an applicable margin, or the greater of the prime rate or one-half of one percent plus the Federal Funds rate. The new facility replaced the former $250 million credit facility consisting of a $125 million three-year facility and a $125 million 364-day facility. At December 31, 2004, $195 million in short and long-term debt was outstanding under the facility.

In October 2002, the Company entered into 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 new borrowing capacity. Interest rates for the program are calculated at the then current commercial paper rate. At December 31, 2004, $50 million was outstanding on the commercial paper program.

In July 2004, the Company issued $65 million in Clark County, Nevada IDRBs Series 2004A, due 2034. The net proceeds from the 5.25% tax-exempt bonds were used to finance construction expenditures in southern Nevada.

In September 2004, the Company remarketed the $20 million 3.35% 2003 Series D IDRBs, due 2038, at a rate of 5.25%. The original 3.35% interest rate was an 18-month rate which was required to be remarketed by September 2004. The 5.25% rate is effective until the 2038 maturity date.

In October 2004, the Company issued $75 million in Clark County, Nevada 5% Series 2004B Industrial Development Refunding Revenue Bonds ("IDRRBs"), due 2033. The Series 2004B IDRRBs were issued at a discount of 0.625%. The proceeds of the new IDRRBs were used to refinance $75 million in 6.5% 1993 Series A IDRBs, due 2033. The redemption of the 1993 Series A IDRBs occurred in December 2004 and included an early redemption premium of 1% ($750,000).

The Company's Revolving Credit Facilities contain financial covenants including a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $475 million plus 25% of the net proceeds of any equity issuance from and after December 31, 2003. In October 2003, a $55.3 million letter of credit, which supports the City of Big Bear $50 million tax-exempt Series A IDRBs, due 2028, was renewed for a three-year period expiring in October 2006. This letter of credit has a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $450 million (adjusted for sales of equity securities after July 1, 2003). If the Company were not in compliance with these covenants, an event of default would occur, which if not cured could cause the amounts outstanding to become due and payable. This would also trigger cross-default provisions in substantially all other outstanding indebtedness of the Company. At December 31, 2004, the Company was in compliance with the applicable covenants.

At December 31, 2004, the effective interest rate including all fees on the 2003 Series A and 2003 Series B IDRBs was 3.44 percent. The 2003 Series A and Series B IDRBs are supported by two letters of credit totaling $101.7 million, which expire in March 2006. These IDRBs are set at weekly rates and the letters of credit support the payment of principal or a portion of the purchase price corresponding to the principal of the IDRBs (while in the weekly rate mode). The interest rate on the tax-exempt variable-rate IDRBs averaged 2.96 percent in 2004 and 2.73 percent in 2003. The rates for the variable-rate IDRBs are established on a weekly basis. The Company has the option to convert from the current weekly rates to daily rates, term rates, or variable-term rates.

The fair value of the revolving credit facility approximates carrying value. Market values for the debentures and fixed-rate IDRBs were determined based on dealer quotes using trading records for December 31, 2004 and 2003, as applicable, and other secondary sources which are customarily consulted for data of this kind. The carrying values of variable-rate IDRBs were used as estimates of fair value based upon the variable interest rates of the bonds.

Estimated maturities of long-term debt for the next five years are $29.8 million, $78.2 million, $119.6 million, $25.9 million, and $0, respectively.

The $7.5 million medium-term notes, 6.76% series, due 2027 contains a put feature at the discretion of the bondholder on one date only in 2007. If the bondholder does not exercise the put on that date, the notes will reach maturity in 2027. If the bondholder exercises the put, the maturities of long-term debt for 2007 will total $127.1 million.

Note 7 – Short-Term Debt

As discussed in Note 6, Southwest has a $250 million three-year credit facility, renewed effective May 2004, of which $150 million is for working capital purposes (and related outstanding amounts will be designated as short-term debt). Short-term borrowings on the credit facility were $95 million and $52 million at December 31, 2004 and 2003, respectively. The weighted-average interest rates on these borrowings were 3.37 percent at December 31, 2004 and 2.04 percent at December 31, 2003.

In December 2004, Paiute purchased the LNG facilities the Company had previously leased. Paiute borrowed $5 million in short-term debt towards the purchase price. The $5 million in short-term debt was repaid in January 2005. At December 31, 2004, the Company had $100 million in short-term borrowings, including the $5 million associated with the LNG purchase.

Note 8 – Commitments and Contingencies

Avista Agreement. In July 2004, the Company announced an agreement with Avista Corporation ("Avista") to purchase Avista's natural gas distribution properties in South Lake Tahoe, California. Avista serves approximately 18,000 customers in this region. The cash purchase price for the properties is $15 million, subject to closing adjustments. The agreement is also subject to customary closing conditions and regulatory review, including approval by the CPUC. The closing is expected in the second quarter of 2005. Once approvals have been received, the properties will be integrated into the northern Nevada operations of Southwest, which include contiguous gas properties in the Lake Tahoe Basin. It is anticipated that Southwest will assume the rates in effect at the time of closing the purchase.

Legal and Regulatory Proceedings. 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 subject will have a material adverse impact on its financial position or results of operations.

Note 9 – Employee Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees and a separate unfunded supplemental retirement plan 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.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("Medicare Act") was signed into law. The Medicare Act includes a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans which have a benefit at least actuarially equivalent to that included in the Medicare Act. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of covered health care costs for employees who retired prior to 1989. A prescription drug benefit is provided for the approximately 100 pre-1989 retirees. The Company elected to defer recognizing the effects of the Medicare Act until authoritative guidance on the accounting for the federal subsidy was issued. Final regulations and authoritative accounting guidance were issued and an actuary determined the Company's prescription drug benefit is not actuarially equivalent to that included in the Medicare Act. Therefore, neither plan assets nor Company operating results were affected.

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 preserve 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. Rate of 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	58 to 70
Debt securities	32 to 38
Other	up to 5

The Company's pension costs for these plans are affected by the amount 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 of 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.

SFAS No. 87 *Employer's Accounting for Pensions* 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 currently available and expected to be available during the period to maturity of the pension benefits. In determining the discount rate, the Company considers highly-rated corporate bonds and considers other measures of interest rates for high quality fixed income investments which match the duration of the liabilities. A rate is chosen based on an evaluation of these measures, rounded to the nearest 25 basis points.

Due to a decline in market interest rates for high-quality fixed income investments, the Company lowered the discount rate to 6.00% at December 31, 2004 from 6.5% at December 31, 2003. This change will result in an increase in pension expense of approximately $5 million for 2005. The reduction in the discount rate resulted in the accumulated benefit obligations of the retirement plan and the supplemental retirement plan exceeding the related plan assets at the measurement date of December 31, 2004. In accordance with generally accepted accounting standards, the Company's balance sheet includes an additional minimum pension liability of $17.4 million, with a corresponding accumulated other comprehensive loss, net of tax, recognized in stockholders' equity.

The following tables set forth the retirement plan and PBOP funded status and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

(Thousands of dollars)	Qualified Retirement Plan 2004	Qualified Retirement Plan 2003	PBOP 2004	PBOP 2003
Change in benefit obligations				
Benefit obligation for service rendered to date at beginning of year (PBO/APBO)	$ 369,094	$319,404	$ 34,367	$ 31,307
Service cost	13,790	12,267	722	675
Interest cost	23,659	21,243	2,180	2,095
Actuarial loss (gain)	31,773	25,580	369	1,850
Benefits paid	(10,200)	(9,400)	(1,650)	(1,560)
Benefit obligation at end of year (PBO/APBO)	$ 428,116	$369,094	$ 35,988	$ 34,367
Change in plan assets				
Market value of plan assets at beginning of year	$ 293,436	$242,159	$ 15,854	$ 12,912
Actual return on plan assets	22,425	49,464	1,653	1,477
Employer contributions	13,003	11,213	1,243	1,465
Benefits paid	(10,200)	(9,400)	—	—
Market value of plan assets at end of year	$ 318,664	$293,436	$ 18,750	$ 15,854
Funded status	$(109,452)	$ (75,658)	$(17,238)	$(18,513)
Unrecognized net actuarial loss (gain)	94,074	56,649	5,685	6,741
Unrecognized transition obligation (2004/2012)	—	—	6,935	7,802
Unrecognized prior service cost	(45)	9	—	—
Prepaid (accrued) benefit cost	$ (15,423)	$ (19,000)	$ (4,618)	$ (3,970)
Accrued benefit liability	$ (22,269)	$ (19,000)	$ (4,618)	$ (3,970)
Additional minimum pension liability adjustment	6,846	—	—	—
	$ (15,423)	$ (19,000)	$ (4,618)	$ (3,970)
Weighted-average assumptions (benefit obligation)				
Discount rate	6.00%	6.50%	6.00%	6.50%
Rate of compensation increase	4.00%	4.25%	4.00%	4.25%
Asset Allocation				
Equity securities	64%	64%	75%	35%
Debt securities	31%	30%	17%	16%
Other	5%	6%	8%	49%
Total	100%	100%	100%	100%

The measurement date used to determine pension and other postretirement benefit measurements was December 31, 2004. Estimated funding for the plans above during 2005 is approximately $16.5 million. The accumulated benefit obligation for the retirement plan was $341 million and $289 million at December 31, 2004 and 2003, respectively. Pension benefits expected to be paid for each of the next five years are the following: 2005 $12.4 million, 2006 $13.1 million, 2007 $13.8 million, 2008 $14.8 million, 2009 $15.8 million. Pension benefits expected to be paid during 2010 to 2014 total $101 million. Retiree welfare benefits expected to be paid for each of the next five years are the following: 2005 $1.5 million, 2006 $1.6 million, 2007 $1.6 million, 2008 $1.7 million, 2009 $1.7 million. Retiree welfare benefits expected to be paid during 2010 to 2014 total $9.3 million.

For PBOP measurement purposes, the per capita cost of covered health care benefits is assumed to increase five percent annually. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of covered health care costs for employees who retired prior to 1989. The assumed annual rate of increase noted above applies to the benefit obligations of pre-1989 retirees only.

Components of net periodic benefit cost:

	Qualified Retirement Plan			PBOP		
(Thousands of dollars)	2004	2003	2002	2004	2003	2002
Service cost	$ 13,790	$ 12,267	$ 11,585	$ 722	$ 675	$ 595
Interest cost	23,659	21,243	20,568	2,180	2,095	1,992
Expected return on plan assets	(28,067)	(27,217)	(27,178)	(1,426)	(1,205)	(1,184)
Amortization of prior service costs	54	57	57	—	—	—
Amortization of unrecognized transition obligation	—	795	837	867	867	867
Amortization of net (gain) loss	—	—	(207)	213	257	—
Net periodic benefit cost	$ 9,436	$ 7,145	$ 5,662	$ 2,556	$ 2,689	$ 2,270
Weighted-average assumptions (net benefit cost)						
Discount rate	6.50%	6.75%	7.25%	6.50%	6.75%	7.25%
Expected return on plan assets	8.75%	8.95%	9.25%	8.75%	8.95%	9.25%
Rate of compensation increase	4.25%	4.25%	4.75%	4.25%	4.25%	4.75%

In addition to the retirement plan, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The plan is noncontributory with defined benefits. Plan costs were $2.7 million in 2004, $2.7 million in 2003, and $3 million in 2002. The accumulated benefit obligation of the plan was $29.5 million at December 31, 2004.

The Employees' Investment Plan provides for purchases of various mutual fund investments and Company common stock by eligible Southwest employees through deductions of a percentage of base compensation, subject to IRS limitations. Southwest matches one-half of amounts deferred. The maximum matching contribution is three percent of an employee's annual compensation. The cost of the plan was $3.5 million in 2004, $3.3 million in 2003, and $3.1 million in 2002. NPL has a separate plan, the cost and liability for which are not significant.

Southwest has a deferred compensation plan for all officers and members of the Board of Directors. The plan provides the opportunity to defer up to 100 percent of annual cash compensation. Southwest matches one-half of amounts deferred by officers. The maximum matching contribution is three percent of an officer's annual salary. 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 percent of Moody's Seasoned Corporate Bond Rate Index.

At December 31, 2004, the Company had two stock-based compensation plans. These plans are accounted for in accordance with APB Opinion No. 25 "Accounting for Stock Issued to Employees." In connection with the stock-based compensation plans, the Company recognized compensation expense of $3 million in 2004, $4.1 million in 2003, and $3 million in 2002. In 2005, the Company will adopt SFAS 123 (revised 2004) and will recognize compensation expense for all stock-based compensation plans based on the fair value provisions of the revised standard. (See **Note 1** for additional details.)

Under one plan, the Company may grant options to purchase shares of common stock to key employees and outside directors. 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 options vest 40 percent at the end of year one and 30 percent at the end of years two and three. The grant date fair value of the options was estimated using the extended binomial option pricing model. The following assumptions were used in the valuation calculation:

	2004	2003	2002
Dividend yield	3.50%	3.94%	3.64%
Risk-free interest rate range	1.66 to 3.23%	1.06 to 2.17%	1.70 to 2.63%
Expected volatility range	13 to 20%	16 to 25%	23 to 31%
Expected life	1 to 3 years	1 to 3 years	1 to 3 years

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

	2004		2003		2002	
	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	1,502	$21.83	1,260	$21.66	1,123	$20.79
Granted during the year	403	23.36	348	21.05	320	21.97
Exercised during the year	(254)	20.21	(106)	17.18	(183)	16.95
Forfeited during the year	(5)	21.83	—	—	—	—
Expired during the year	—	—	—	—	—	—
Outstanding at year end	1,646	$22.46	1,502	$21.83	1,260	$21.66
Exercisable at year end	1,010	$22.36	868	$21.96	677	$21.46

The weighted-average grant-date fair value of options granted was $1.65 for 2004, $1.90 for 2003, and $2.69 for 2002. The following table summarizes information about stock options outstanding at December 31, 2004 (thousands of options):

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable	Weighted-Average Exercise Price
$15.00 to $19.13	171	4.3 Years	$17.71	171	$17.71
$20.49 to $24.50	1,357	7.8 Years	$22.49	721	$22.39
$28.75 to $28.94	118	4.5 Years	$28.91	118	$28.91

In addition to the option plan, the Company may issue restricted stock in the form of performance shares to encourage key employees to remain in its employment 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 after three years from issuance and are subject to a final adjustment as determined by the Board of Directors. The following table summarizes the activity of this plan (thousands of shares):

Year Ended December 31,	2004	2003	2002
Nonvested performance shares at beginning of year	381	345	314
Performance shares granted	156	147	122
Performance shares forfeited	—	—	—
Shares vested and issued *	(221)	(111)	(91)
Nonvested performance shares at end of year	316	381	345
Average grant date fair value of award	$22.70	$22.21	$22.35

* Includes shares converted for taxes and retiree payouts

Note 10 – Income Taxes

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

Year Ended December 31,	2004	2003	2002
Current:			
Federal	$ (225)	$ 24	$ 5,546
State	(1,186)	(4,421)	3,462
	(1,411)	(4,397)	9,008
Deferred:			
Federal	28,607	17,274	14,819
State	3,041	4,005	(2,410)
	31,648	21,279	12,409
Total income tax expense	$30,237	$16,882	$21,417

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

Year Ended December 31,	2004	2003	2002
Deferred federal and state:			
Property-related items	$ (3,165)	$22,608	$ 44,491
Purchased gas cost adjustments	34,923	1,030	(29,087)
Employee benefits	240	(1,767)	(5,113)
All other deferred	518	276	2,986
Total deferred federal and state	32,516	22,147	13,277
Deferred ITC, net	(868)	(868)	(868)
Total deferred income tax expense	$31,648	$21,279	$ 12,409

The consolidated effective income tax rate for the period ended December 31, 2004 and the two prior periods differs 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,	2004	2003	2002
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state taxes	2.8	2.4	1.0
Property-related items	0.8	1.3	–
Effect of closed tax years and resolved issues	(1.8)	(3.6)	–
Tax credits	(1.0)	(1.6)	(1.3)
Corporate owned life insurance	(0.7)	(2.3)	–
All other differences	(0.3)	(0.7)	(1.9)
Consolidated effective income tax rate	34.8%	30.5%	32.8%

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

December 31,	2004	2003
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 7,500	$ 8,037
Employee benefits	33,710	27,416
Alternative minimum tax	24,028	36,681
Net operating losses & credits	59,977	24,200
Other	5,607	6,076
Valuation allowance	—	—
	130,822	102,410
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	365,242	331,770
Regulatory balancing accounts	40,301	5,379
Property-related items previously flowed through	10,574	11,737
Unamortized ITC	12,065	12,933
Debt-related costs	6,942	5,777
Other	4,117	5,232
	439,241	372,828
Net deferred tax liabilities	$308,419	$270,418
Current	$ 26,676	$ (6,914)
Noncurrent	281,743	277,332
Net deferred tax liabilities	$308,419	$270,418

At December 31, 2004, the Company has a federal net operating loss carryforward of $157 million which expires in 2022 to 2024 and a federal general business credit carryforward of $1.4 million which expires in 2011 to 2022. The Company also has an Arizona net operating loss carryforward of $63.6 million which expires in 2005 to 2009 and an Arizona tax credit carryforward of $253,000 which expires in 2005 to 2007. The Company also has a California net operating loss carryforward of $2.7 million which expires in 2013 to 2014.

Note 11 – 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, transporting, and distributing natural gas. Revenues are generated from the sale and transportation of natural gas. The construction services segment is 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 December 31, 2004 and 2003, consolidated accounts receivable included $8.3 million and $5.8 million, respectively, which were not eliminated during consolidation.

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, 2004 is as follows (thousands of dollars):

2004	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,262,052	$153,392		$1,415,444
Intersegment sales	—	61,616		61,616
Total	$1,262,052	$215,008		$1,477,060
Interest expense	$ 85,861	$ 645		$ 86,506
Depreciation and amortization	$ 130,515	$ 15,503		$ 146,018
Income tax expense	$ 24,698	$ 5,539		$ 30,237
Segment income	$ 48,354	$ 8,421		$ 56,775
Segment assets	$2,843,199	$ 99,120	$(4,203)	$2,938,116
Capital expenditures	$ 274,748	$ 27,940		$ 302,688

2003	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,034,353	$137,717		$1,172,070
Intersegment sales	—	58,934		58,934
Total	$1,034,353	$196,651		$1,231,004
Interest expense	$ 78,931	$ 855		$ 79,786
Depreciation and amortization	$ 120,791	$ 15,648		$ 136,439
Income tax expense	$ 13,920	$ 2,962		$ 16,882
Segment income	$ 34,211	$ 4,291		$ 38,502
Segment assets	$2,528,332	$ 79,774		$2,608,106
Capital expenditures	$ 228,288	$ 12,383		$ 240,671

2002	Gas Operations	Construction Services	Adjustments	Total
Revenues from unaffiliated customers	$1,115,900	$134,625		$1,250,525
Intersegment sales	—	70,384		70,384
Total	$1,115,900	$205,009		$1,320,909
Interest expense	$ 78,505	$ 1,466		$ 79,971
Depreciation and amortization	$ 115,175	$ 15,035		$ 130,210
Income tax expense	$ 18,493	$ 2,924		$ 21,417
Segment income	$ 39,228	$ 4,737		$ 43,965
Segment assets	$2,345,407	$ 87,521		$2,432,928
Capital expenditures	$ 263,576	$ 19,275		$ 282,851

Construction services segment assets include deferred tax assets of $4.2 million in 2004, which were netted against gas operations segment deferred tax liabilities during consolidation.

Note 12 – Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Thousands of dollars, except per share amounts)	March 31	June 30	September 30	December 31
2004				
Operating revenues	$473,400	$278,697	$264,467	$460,496
Operating income (loss)	85,802	5,954	(9,017)	87,028
Net income (loss)	41,044	(8,362)	(16,353)	40,446
Basic earnings (loss) per common share *	1.19	(0.24)	(0.46)	1.12
Diluted earnings (loss) per common share *	1.18	(0.24)	(0.46)	1.11
2003				
Operating revenues	$403,285	$255,852	$220,162	$351,705
Operating income (loss)	62,314	11,789	(8,285)	69,287
Net income (loss)	25,539	(4,104)	(17,407)	34,474
Basic earnings (loss) per common share *	0.76	(0.12)	(0.51)	1.01
Diluted earnings (loss) per common share *	0.76	(0.12)	(0.51)	1.00
2002				
Operating revenues	$499,501	$261,123	$223,863	$336,422
Operating income (loss)	80,317	7,044	(3,337)	62,475
Net income (loss)	42,896	(20,610)	(16,136)	37,815
Basic earnings (loss) per common share *	1.32	(0.63)	(0.49)	1.14
Diluted earnings (loss) per common share *	1.30	(0.63)	(0.49)	1.13

* 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 the 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.

Note 13 – Merger-related Litigation Settlements

Litigation related to the now terminated acquisition of the Company by ONEOK, Inc. ("ONEOK") and the rejection of competing offers from Southern Union Company ("Southern Union") was resolved during 2002. In August 2002, the Company reached final settlements with both Southern Union and ONEOK related to this litigation. The Company paid Southern Union $17.5 million to resolve all remaining Southern Union claims against the Company and its officers. ONEOK paid the Company $3 million to resolve all claims between the Company and ONEOK. The net after-tax impact of the settlements was a $9 million charge and was reflected in the second quarter 2002 financial statements. The Company and one of its insurance providers were in dispute over whether the insurance coverage applied to the Southern Union settlement and related litigation defense costs. Because of the dispute, the Company did not recognize any benefit for potential insurance recoveries related to the Southern Union settlement in the second quarter of 2002.

In December 2002, the Company negotiated a $16.25 million settlement with the insurance provider related to the coverage dispute. Income from the settlement was recognized in the fourth quarter of 2002 and amounted to $9 million after-tax.

Note 14 – Acquisition of Black Mountain Gas Company

In October 2003, the Company acquired all of the outstanding stock of Black Mountain Gas Company.

The assets acquired and the liabilities assumed at the acquisition date were as follows (thousands of dollars):

Gas plant	$23,974
Less: accumulated depreciation	(5,992)
Net utility plant	17,982
Other property and investments	1,500
Accounts receivable, net of allowances	504
Prepaids and other current assets	163
Deferred charges and other assets (includes goodwill of $5,445)	5,610
Total assets acquired	25,759
Accounts payable	219
Customer deposits	55
Deferred purchased gas costs	112
Accrued general taxes	144
Other deferred credits	1,229
Total liabilities assumed	1,759
Cash acquisition price	$24,000

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, 2004. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

March 14, 2005

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Southwest Gas Corporation:

We have completed an integrated audit of Southwest Gas Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholders' equity present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Southwest Gas Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement obligations as of January 1, 2003, financial instruments with characteristics of both debt and equity and certain variable interest entities as of July 1, 2003.

Internal Control Over Financial Reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Southwest Gas Corporation maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, Southwest Gas Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control - Integrated Framework issued by the COSO. Southwest Gas Corporation management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of Southwest Gas Corporation's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Los Angeles, California
March 14, 2005

Shareholder Information

Stock Listing Information

Southwest Gas Corporation's 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 listed under "SoWestGas."

Annual Meeting

The Annual Meeting of Shareholders will be held on May 5, 2005 at 10:00 a.m. at the Rio Suites Hotel and Casino, I-15 and Flamingo Road, Las Vegas, Nevada.

Dividend Reinvestment and Stock Purchase Plan

The Southwest Gas Corporation Dividend Reinvestment and Stock Purchase Plan (DRSPP) provides its 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 any brokerage commission.

The DRSPP features include:

Initial investments of $100, up to $100,000 annually
Automatic investing
No commissions on purchases
Safekeeping for common stock certificates

For more information contact:

Shareholder Services, Southwest Gas Corporation, P. O. Box 98511, Las Vegas, NV 89193-8511 or call (800) 331-1119

Dividends

Dividends on common stock are declared quarterly by the Board of Directors. As a general rule, they are payable on the first day of March, June, September and December.

Investor Relations

Southwest Gas Corporation is committed to providing relevant and complete investment information to shareholders, individual investors and members of the investment community. Additional copies of the Company's 2004 Annual Report on Form 10-K, without exhibits, as filed with the Securities and Exchange Commission may be obtained upon request free of charge. Additional financial information may be obtained by contacting Kenneth J. Kenny, Investor Relations, Southwest Gas Corporation, P. O. Box 98510, Las Vegas, NV 89193-8510 or by calling (702) 876-7237.

Southwest Gas Corporation information is also available on the Internet at www.swgas.com. For non-financial information, please call (702) 876-7011.

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BOARD OF DIRECTORS AND OFFICERS

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Executive Vice President/Chief Financial Officer and Corporate Secretary
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Senior Vice President/Finance

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