SWIFT ENERGY COMPANY

2004 ANNUAL REPORT

BRIGHT FUTURE

25 years

PROUD PAST

HIGHLIGHTS

	2004	2003	Percent Change
Revenues	$310,276,774	$208,900,983	49%
Oil & Gas Sales	$311,285,172	$211,032,639	48%
Costs & Expenses	$208,836,532	$158,161,805	32%
Income Before Change in Accounting Principle	$68,450,917	$34,270,664	100%
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	-	($4,376,852)	(100)%
Net Income	$68,450,917	$29,893,812	129%
Basic Earnings per Share Before Change in Accounting Principle	$2.46	$1.25	97%
Change in Accounting Principle (per Share)	-	($0.16)	(100)%
Earnings per Share–Basic	$2.46	$1.09	126%
Earnings per Share–Diluted	$2.41	$1.08	123%
Total Assets	$990,573,147	$859,838,544	15%
Working Capital	($14,232,295)	($35,892,385)	(60)%
Current Ratio	0.79	0.48	65%
Long-Term Debt	$357,500,000	$340,254,783	5%
Stockholders' Equity	$474,172,140	$397,391,264	19%
Long-Term Debt to Equity Ratio	0.75	0.86	(13)%
Return on Assets (Net Income / Average Assets)	7.4%	3.7%	100%
Return on Stockholders' Equity (Net Income / Average Equity)	15.7%	7.8%	101%
Net Cash Provided by Operating Activities	$182,582,887	$110,827,279	65%
Total Production (Mcfe)	58,318,502	53,158,384	10%
Natural Gas Production (Mcf)	23,741,726	28,002,719	(15)%
Oil & Condensate Production (Bbls)	4,722,329	3,369,398	40%
Natural Gas Liquids Production (Bbls)	1,040,467	823,214	26%
Average Composite Prices Received ($/Mcfe)	$5.34	$3.97	34%
Average Natural Gas Prices Received ($/Mcf)	$4.12	$3.42	20%
Average Oil & Condensate Prices Received ($/Bbl)	$40.24	$29.89	35%
Average Natural Gas Liquids Prices Received ($/Bbl)	$22.52	$17.60	28%
Total Proved Reserves (Mcfe)	799,849,539	820,364,284	(3)%
Proved Natural Gas Reserves (Mcf)	318,246,294	335,804,862	(5)%
Proved Oil & Condensate Reserves (Bbls)	65,655,041	63,808,873	3%
Proved Natural Gas Liquids Reserves (Bbls)	14,612,167	16,951,030	(14)%
Weighted Average Shares Outstanding	27,822,413	27,357,579	2%
Year-End Shares Outstanding	28,089,764	27,484,091	2%
Number of Shareholders of Record	298	348	(14)%
Number of Shareholders in Street Name (est.)	5,752	5,775	0%
Market Price of Common Stock at Year-End	$28.94	$16.85	72%
Price-Earnings Ratio (Year-End Stock Price / EPS–Basic)	11.8	15.5	(24)%
Number of Employees	272	241	13%

See page 34 regarding the forward-looking statements in this report.
See page 71 for a glossary of abbreviations and terms.

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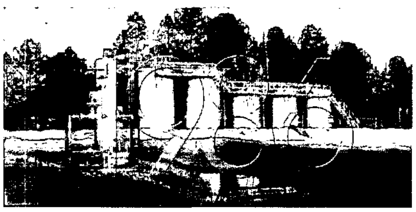
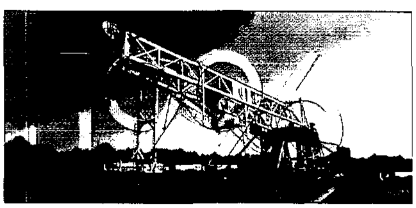
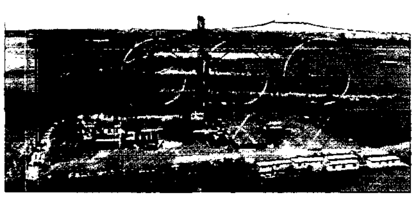
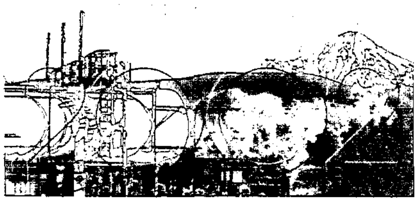
PROUD PAST BRIGHT FUTURE

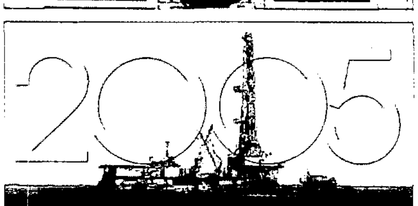
25 years











SWIFT ENERGY COMPANY 2004 ANNUAL REPORT

Additional information about Swift Energy Company is available on the Internet at www.swiftenergy.com. The information includes press releases, Swift's code of ethics, and Company hedging positions. It also includes Swift's annual reports on Form 10-K, quarterly reports on Form 10-Q and links to current reports on Form 4 and Form 8-K, all available free of charge and updated as soon as practicable after the Company has filed with the U.S. Securities and Exchange Commission. Visitors to swiftenergy.com can register to receive periodic e-mail updates concerning new information available at the web site.

COMPANY PROFILE

Celebrating 25 Years of Operations

Swift Energy Company is an independent oil and natural gas company engaged in the development, exploration, acquisition, and operation of oil and gas properties, with a focus in the United States on onshore and inland water areas of the Louisiana and Texas Gulf Coast and a focus in New Zealand on onshore areas of the north island's Taranaki Basin. Currently celebrating its 25th anniversary, the Company was founded in October 1979 and has its principal headquarters in Houston, Texas.

1979 Swift Energy Company founded.
1981 Swift completes initial public offering of common stock.
1984 Company listed on the American Stock Exchange (AMEX) under "SFY."
1991 Listing moved to the New York Stock Exchange (NYSE).
1996 Swift ranked 20th in stock price performance on NYSE.
2000 Swift ranked 15th in stock price performance on NYSE.
2004 Common stock reached $28.94 per share at year-end, 72% above year-end 2003 value.

MISSION & GOALS

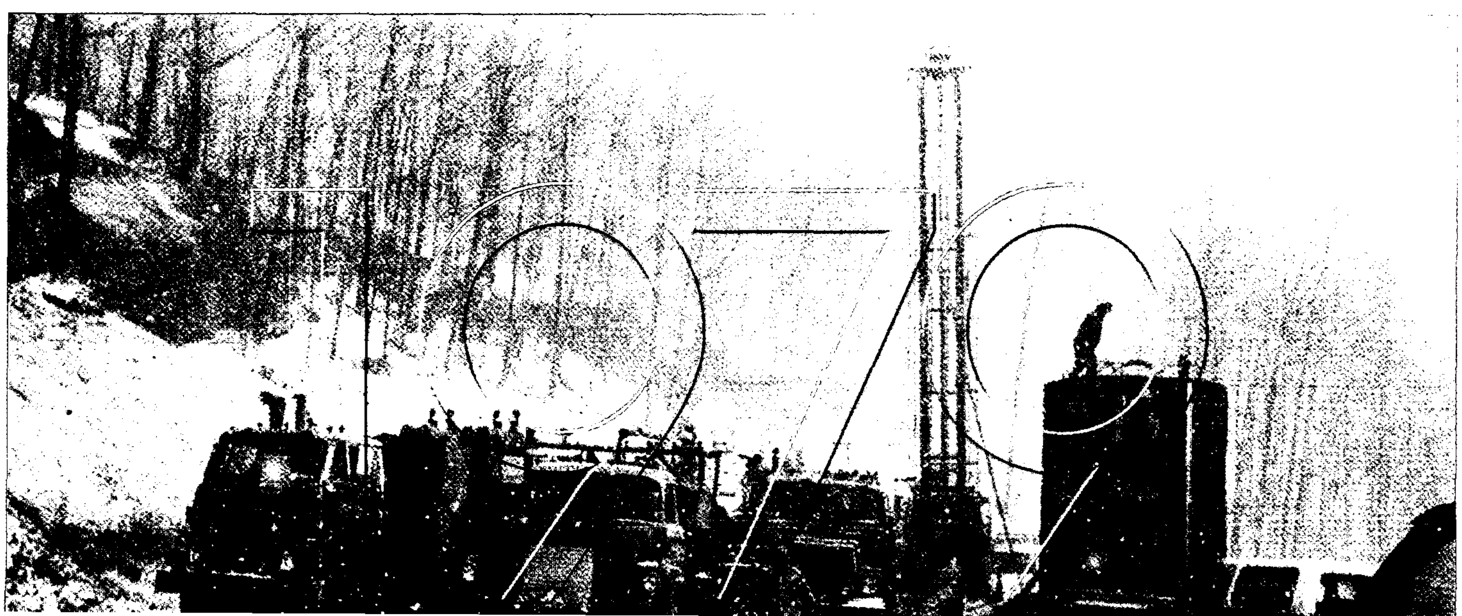
As a natural resource company, Swift Energy is committed to achieving efficient, sustained growth in the volume and value of its proved oil and gas reserves, while simultaneously maintaining high standards for ethical conduct, the protection of health and safety, and the preservation of environmental quality. In all of its activities, the Company focuses on optimizing stakeholder value by building a balanced portfolio of oil and gas properties with diversified production profiles and an assortment of growth opportunities covering a range of risks and potential rewards.

Over the last five years, the Company has achieved an average compounded growth rate in proved oil and gas reserves of approximately 12% per year. Swift's success in sustaining reserves growth in a volatile pricing environment has enabled it to achieve five-year compounded growth rates of approximately 6% per year in production, 23% per year in oil and gas sales, 20% per year in cash flows from operating activities, and 18% per year in diluted earnings per share.

During 2004, year-end proved reserves decreased by 3% from the previous year to about 800 billion cubic feet equivalent (Bcfe). This slight reduction largely resulted from a strategic decision to slow down drilling in South Louisiana during 2004 in order to acquire three-dimensional seismic data for that area and to implement significant facilities improvements. Although the slowdown contributed to lower reserves additions and increased finding and development costs in the short-term, the seismic data will benefit the Company's future long-term drilling program.

Over the next five years, Swift's primary strategic goals are to increase its proved reserves at an average rate of 5% to 10% per year and its production at an average rate of 7% to 12% per year.

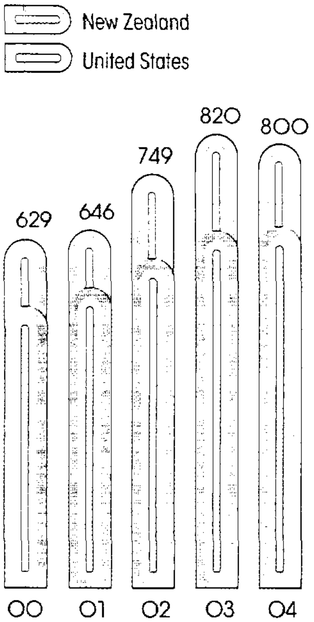
Below: The hydraulic fracturing of a West Virginia well early in Swift's history.



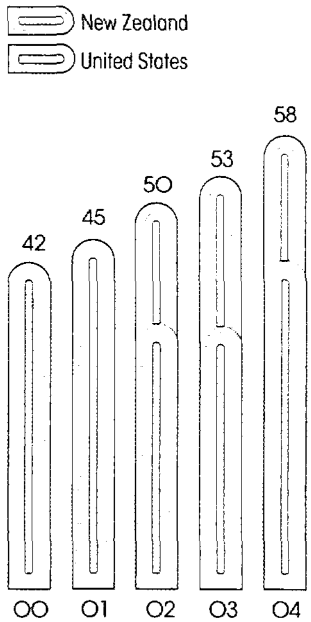
BUSINESS STRATEGY

Swift's reserves growth is primarily accomplished through a mix of exploratory and development drilling and producing property acquisitions. The specific mix of drilling and acquisitions is continually adjusted in response to changing industry conditions.

YEAR-END PROVED RESERVES (Bcfe)



OIL & GAS PRODUCTION (Bcfe)



Development drilling is generally focused in the Company's core areas of operation. Domestically, these include the Lake Washington Area and Masters Creek Area in Louisiana and the AWP Olmos Area and Brookeland Area in Texas. In New Zealand, they include the Rimu/Kauri Area and the TAWN Area.

Exploratory drilling is conducted both in these core areas and in other regions that Swift believes have potential for becoming core areas of operation. In 2004, Swift primarily focused its drilling activities in the Lake Washington Area in South Louisiana and plans to continue to do so in 2005.

In its acquisitions activities, the Company continually reviews opportunities to purchase strategic producing properties where performance can be enhanced through development drilling or improved operating efficiencies. This approach led to the purchase of the Company's initial reserves in the AWP Olmos Area in 1988, the Brookeland and Masters Creek Areas in 1998, the Lake Washington Area in 2001, and the TAWN Area in 2002.

In 2004, Swift purchased interests in what is anticipated to become two additional core areas in South Louisiana —the Cote Blanche Island Field in St. Mary Parish and the Bay de Chene Field in Lafourche Parish and Jefferson Parish. Swift Energy plans to initiate a multiyear exploitation program in these areas beginning in the second half of 2005.

INDUSTRY ENVIRONMENT

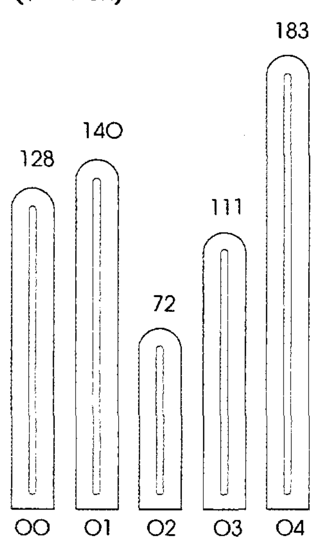
Volatility in the prices of crude oil, natural gas, and natural gas liquids (NGLs) can have a significant impact on the revenues and earnings from Swift's operations. In 2004, average domestic crude oil prices received by the Company increased 34% to $40.04 per barrel, average domestic NGL prices increased 26% to $24.84 per barrel, and domestic natural gas prices increased 13% to $5.74 per thousand cubic feet (Mcf).

In New Zealand, Swift Energy received an average of $42.15 per barrel for its crude oil, an increase of 42% from 2003 prices. Average NGL prices increased 33% to $17.96 per barrel, and natural gas prices rose 30% to $2.38 per Mcf. Unlike crude oil sales, which are denominated in U.S. dollars, New Zealand natural gas and NGL prices are denominated in New Zealand dollars, which strengthened in relation to the U.S. dollar over the course of 2003 and 2004, leading to some of the appreciation in New Zealand product prices received by Swift.

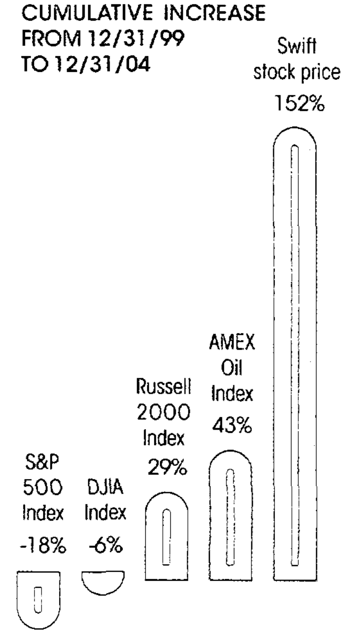
PERFORMANCE COMPARISON

Swift's policy is to reinvest cash flows rather than pay cash dividends in order to promote long-term growth in the value of the Company's common stock. Although industry price cycles can have a substantial impact on year-to-year performance, over the longer term Swift has achieved consistent growth in shareholder value. At the end of 2004, the five-year cumulative appreciation in Swift's year-end stock price totaled 152%, comparing favorably with five-year increases in the AMEX Oil Index (43%), the Russell 2000 index (29%), the Dow Jones Industrial Average (-6%), and the S&P 500 index (-18%).

NET CASH PROVIDED BY OPERATING ACTIVITIES ($ Million)



CUMULATIVE INCREASE FROM 12/31/99 TO 12/31/04



Swift Energy's common stock has been traded under the symbol "SFY" on the New York Stock Exchange (NYSE) since 1991.

LETTER TO STOCKHOLDERS

Moving from a Proud Past to a Bright Future

In life's journey, milestones provide incentives for checking our direction and distance—to make sure that we are still closing in on our desired destination. On October 11, 2004, an important milestone occurred for us in the celebration of the 25th anniversary of the founding of our Company, making it a good time to ask ourselves if we are where we should be and if our plans for the future will take us where we want to go.

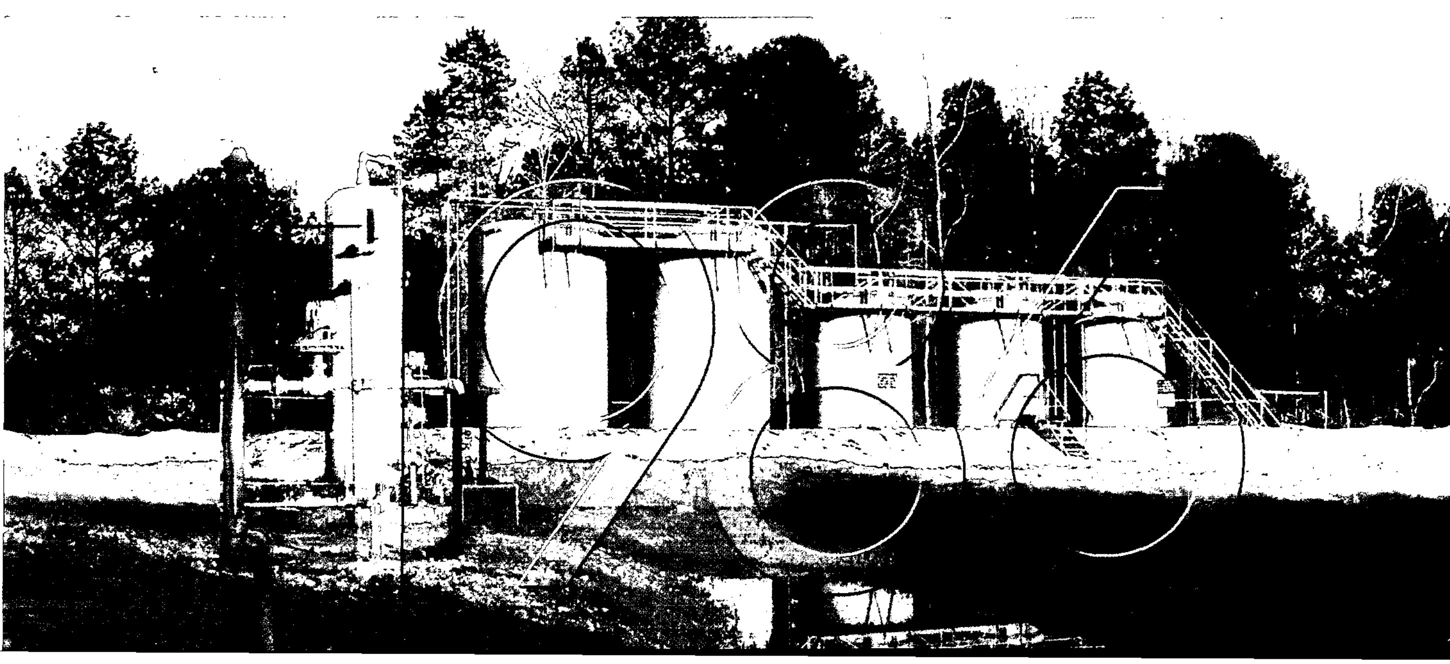
Our outstanding results for 2004 tell us where we are after our first 25 years. In 2004, we achieved increases of 10% in production, 48% in oil and natural gas sales, 65% in net cash provided by operating activities, and 123% in diluted earnings per share. Moreover, our fourth-quarter production and earnings per share reached the highest levels in the Company's history.

Admittedly, these achievements were facilitated by strong oil and gas prices as we were realizing record production. The average composite price we received for our 2004 production increased 34% from the previous year to $5.34 per thousand cubic feet of natural gas equivalent (Mcfe), or $32.04 per barrel of oil equivalent (BOE). But it was our long-term strategy for operating in the volatile oil and gas industry that had positioned us to take advantage of the increased prices. In that strategy we adjust to the swings in oil and gas prices by emphasizing drilling—exploratory and/or development—during periods of relatively strong product prices and, except for strategic properties, limiting acquisitions to times of relatively weak prices, thereby adding oil and gas reserves at the most economical prices.

During the high-price environment of 2004, we made the strategic decision to optimize our drilling results, and thereby our earnings, by focusing on low-risk development drilling both domestically and internationally. At the same time we reduced the pace of drilling in our Lake Washington Area in South Louisiana in order to acquire three-dimensional seismic data over the entire acreage and also to make facility improvements in the field. Although the low-risk emphasis and slowdown resulted in a 3% decline in our Company-wide year-end reserves, as well as increased finding and development costs, we anticipate that these activities will significantly benefit our long-term drilling program and improve the quality of our reserves. In fact, with increased contributions from Lake Washington and other areas, we expect the Company to have a 7% to 12% growth in both production and reserves in 2005, with an increasing percentage of long-lived reserves.

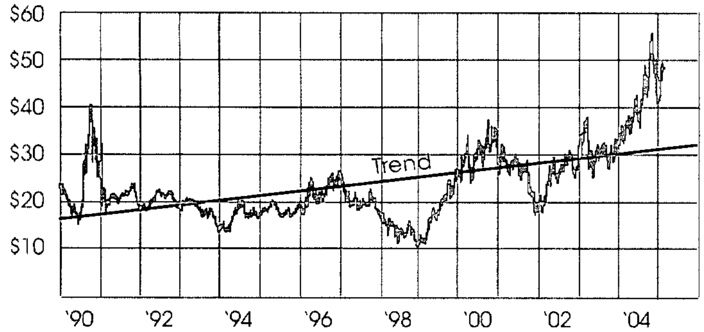
1979	First drilling program begun in West Virginia.
1982-1983	Drilling expanded into Kansas, Alabama, and Wyoming.
1984-1987	Low prices prompted strategic transition from drilling to producing property acquisitions.
1988-1995	Company expanded through exploitation of acquired properties.
1996-1997	Drilling reemphasized with price improvements; focus on South Texas Olmos sands.
1998-2000	New core areas acquired in Austin Chalk trend; operations begun in New Zealand.
2001-2004	New core areas acquired in South Louisiana and New Zealand.

Below: An early acquired property in Texas.



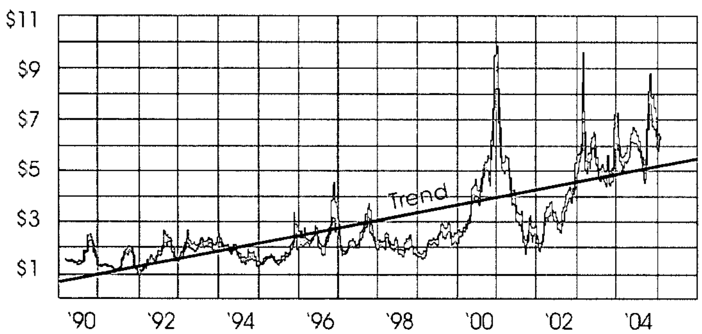
NYMEX Crude Oil Futures

$/Barrel, Near-Month Contract, 1/1/1990 to 1/31/2005



NYMEX Natural Gas Futures

$/MMBtu, Near-Month Contract, 1/1/1990 to 1/31/2005



There are good reasons for our optimism. We believe that oil and gas prices, while remaining volatile, have entered a period of long-term strength. Worldwide oil production could peak at any time within the next 20 years, and with the increasing global oil demand, supplies are likely to tighten well in advance of any production downturn. U.S. natural gas prices are also strengthening due to a slowdown in the growth rate of Canadian imports and the inability of U.S. production to meet the growing demand. Similarly, the decline in gas production from New Zealand's largest field is leading to a tightening of supplies and higher prices in that country.

At Swift Energy, we have planned for this era of the industry. We know that even after global oil production begins a permanent decline, abundant opportunities for independent oil and gas companies will remain available for decades. In the United States, for example, oil production peaked in 1970 and has steadily and inevitably declined ever since. Even so, excellent opportunities in domestic petroleum production can still be found.

We have demonstrated that with our 2001 acquisition in the Lake Washington Field. Applying modern technologies, we increased our production from the field's Miocene sands from less than 1,000 gross BOE per day at the time of purchase to a year-end 2004 exit rate of approximately 15,500 gross BOE per day. We also increased our estimated net proved reserves in the area more than fivefold, from 7.7 million BOE to 45.4 million BOE, even after more than three years of production. With these gains, we have become the largest independent crude oil producer in Louisiana.

We still have opportunities for significant long-term growth in Lake Washington. At the depths we have drilled to date, less than 10,000 feet, we have already encountered over 70 different pay zones and discovered an additional major producing horizon. It was in order to better understand these and deeper horizons in the field that we conducted the three-dimensional seismic survey in that area. We have since merged our data with purchased three-dimensional seismic data for an adjacent area and are in the process of analyzing the total data set covering over 600 square miles with state-of-the-art reprocessing techniques. We are also integrating the seismic data with geophysical and geological data. Based largely on these results, we currently plan to drill at least 26 development wells and four exploratory wells in Lake Washington during 2005. As we drill deeper, we expect to find gas reserves as well as oil reserves.

To further expand our activities in South Louisiana, we recently acquired 100% working interests in two additional properties in the region that also produce from Miocene sands surrounding salt domes. Planning to initiate drilling in these areas in mid-2005, we are currently purchasing existing three-dimensional seismic data for one of the fields to merge with our large data set. We are also investigating obtaining seismic data for the other field or possibly performing our own seismic surveys over both fields.

Meanwhile, our oldest core area of operations, the AWP Olmos Area in South Texas, continues to be a steady gas producer from the Olmos sand and will undergo further development in 2005. And our Brookeland Area in East Texas and Masters Creek Area in Central Louisiana, both producing from horizontal wells drilled in the Austin Chalk trend, will see similar activity in 2005.

In New Zealand, where we have exploration permits for more onshore acreage than any other company, we plan to launch several exploratory projects in 2005. Among five exploratory wells planned, one will be drilled northwest of our Rimu/Kauri Area and two will be in our TAWN Area. At the same time, development drilling will continue in the Rimu/Kauri Area, where the Kauri sands and Manutahi sands, both of which we discovered when drilling to a deeper horizon, will be the targets.

From our perspective, all of the foregoing underscores the theme of this 25th anniversary report—that Swift Energy Company has a past to be proud of and a bright future in a still vital industry. We feel extraordinarily good about the direction in which the Company is going and have the utmost confidence that our strategy and our people will bring us ever closer to our desired destination.

A. Earl Swift
Chairman

A. Earl Swift

Terry E. Swift
Chief Executive Officer

Terry E. Swift

SHAREHOLDER VALUE

Delivering Results

In 2004, Swift Energy's shareholders again enjoyed strong appreciation of Swift Energy's common stock. For the second year in a row, the year-end stock price increased over 70%, having risen 74% from $9.67 at year-end 2002 to $16.85 at year-end 2003 and then rising 72% to $28.94 at year-end 2004. These increases were made possible by substantial improvements in diluted earnings per share, which rose 140% in 2003 and 123% in 2004.

Although operating in a cyclical oil and gas industry, Swift has built a legacy of steady growth in shareholder value. Since its first full year of operations in 1980, it has achieved a compounded growth rate of 24% a year in proved oil and gas reserves per share of common stock, with proved reserves of 28 Mcfe per share at year-end 2004. To accomplish this growth, it uses the industry's cyclical nature to its own advantage. By emphasizing drilling when prices are high and producing property acquisitions when oil and gas prices are low, the Company adds reserves in a cost-effective manner. Over the past five years, its reserves replacements have averaged approximately 240% of production with an average replacement cost of approximately $1.47 per Mcfe. In addition, the Company has maintained a disciplined capital structure with a strong liquidity position, giving it stability in industry downturns and providing the flexibility needed to pursue opportunities as they arise.

Another important measure of value creation is the percentage of total reserves classified as developed. At year-end 2004, Swift's proved developed reserves amounted to 56% of total proved reserves, down from 59% at year-end 2003, but up from 50% at the end of 2001.

Swift has also kept costs within the range of its strategic goals, which include limiting the three-year averages for replacement costs ($1.48 per Mcfe) and production costs ($1.03 per Mcfe) to one-third of the three-year average for wellhead prices.

From 2002 to 2004, Swift's wellhead prices averaged $4.12 per Mcfe. Over that same time period, the Company's replacement costs averaged 36% of wellhead prices, and its production costs averaged 25%.

With this excellent track record of growth, Swift remains confident that it has laid a strong foundation for building shareholder value in the years ahead.

1981	Initial public offering of 1.3 million shares of common stock at $2.50 per share.
1989	Public offering of 0.66 million shares of common stock at $10.625 per share.
1992	Institutional offering of 0.99 million shares of stock with net proceeds of $6.4 million.
1994	A 10% stock dividend declared.
1995	Public offering of 5.75 million shares of common stock at $8.50 per share.
1996	Stockholders' equity increased $27.65 million with the conversion of debentures into 2.34 million shares of common stock.
1997	A second 10% stock dividend declared.
1999	Public offering of 4.6 million shares of common stock at $9.75 per share.
2000	Approximately $100 million of convertible notes converted into 3.16 million shares of common stock.
2002	Public offering of 1.725 million shares of common stock issued at $18.25 per share.

Below: A 1992 seismic survey in Oklahoma.

25 years

DOMESTIC OPERATIONS

Building Quality Assets

Swift Energy's domestic drilling operations throughout 2004 continued to be focused in the Lake Washington Area in Plaquemines Parish, Louisiana, and, to a lesser extent, in the AWP Olmos Area in McMullen County, Texas. Both these areas hold long-lived reserves—mostly oil in Lake Washington and natural gas in AWP—and both have a high percentage of drilling successes, with each contributing significantly toward maintaining the Company's production over a multiyear period. Together, they also hold 62% of Swift's proved undeveloped domestic reserves, so that drilling programs will continue in the two areas for a number of years.

During 2004, Swift Energy drilled a total of 54 domestic wells—10 exploratory wells with a 40% success rate and 44 development wells with an 84% success rate, for an overall success rate of 76%. These were fewer than the 71 wells drilled in 2003 because of a scheduled slowdown in Lake Washington to accommodate an extensive three-dimensional seismic survey and facility improvements.

1988	Initial interests acquired in South Texas AWP Olmos Field.
1989	Swift established first core area in AWP Olmos Field.
1996	AWP acreage doubled and 123 wells drilled in field.
1997	AWP acreage increased again and 137 wells drilled in field.
1998	Swift established core areas in Texas Brookeland Field and Louisiana Masters Creek Field.
1999	Year-end reserves for Brookeland and Masters Creek more than doubled.
2001	Swift established core area in Louisiana's Lake Washington Field.
2004	Lake Washington year-end daily production increased 1,400% from time of initial acquisition.

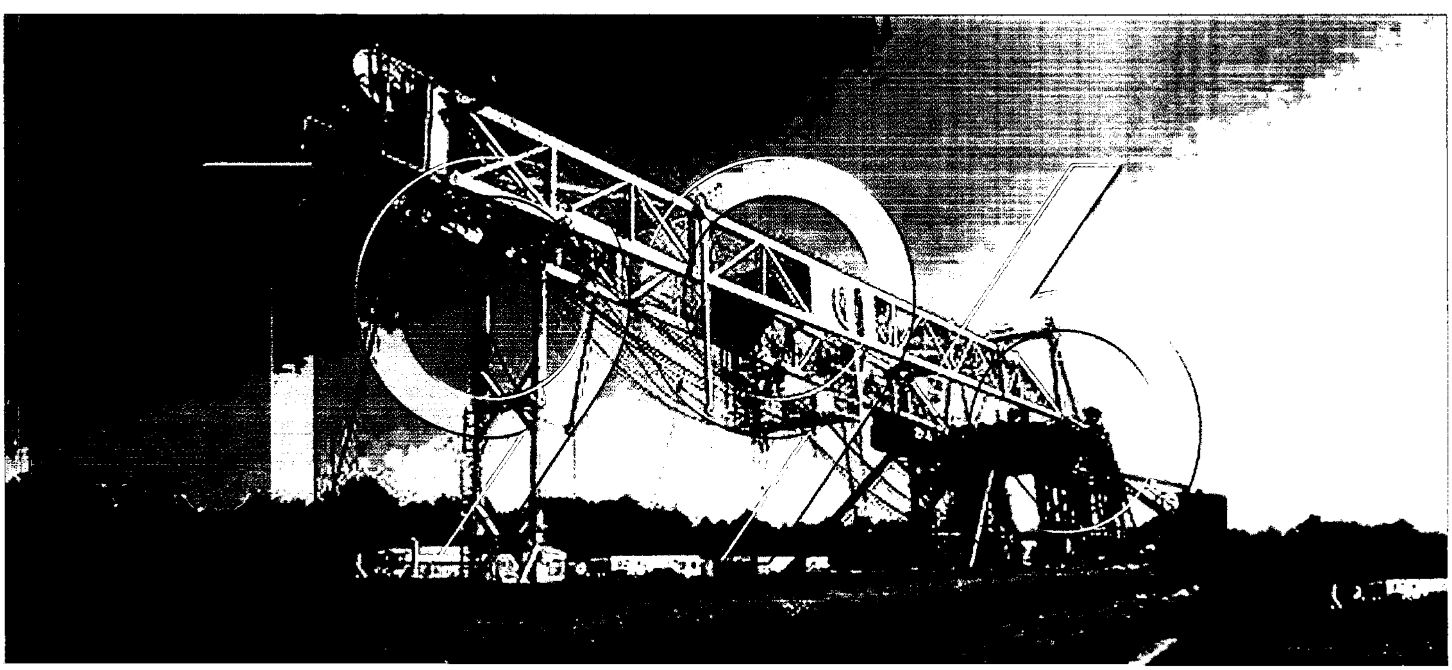
The domestic wells drilled in core areas in 2004 included 30 wells in Lake Washington and 15 wells in AWP, all with 100% Swift working interest, and one well in the Masters Creek Area in Central Louisiana with a 94% working interest. No wells were drilled in the Brookeland Area in East Texas. Outside its core areas, Swift drilled or participated with smaller working interests in seven wells in South Texas (see page 20) and in one well drilled in Mobile County, Alabama.

Swift's total domestic production in 2004 was 42.1 Bcfe, exceeding its 2003 domestic production by 25%. Domestic production comprised 72% of the Company's combined production from the United States and New Zealand. With most of Swift's recent drilling activities located in Lake Washington, that field was the Company's largest domestic producer, contributing 55% of Swift's domestic production in 2004 compared to 36% in 2003. AWP contributed 21% in 2004 compared to 25% in 2003.

Swift's domestic proved reserves at year-end 2004 totaled 652.7 Bcfe, comprising 81.6% of the Company's total proved reserves. Domestic reserves were up only slightly from their year-end 2003 value; however, Lake Washington reserves increased 11.6 Bcfe from 2003 levels. Lake Washington and AWP together held over 71% of Swift's year-end domestic reserves.

With the increasing dominance of Lake Washington's oil reserves, plus the acquisition of two other similar properties in 2004 (see page 19), Swift's domestic proved year-end natural gas reserves have changed from 71.7% of total reserves at year-end 2000 to 36.8% of total reserves at year-end 2004.

Below: Rigging up a drilling rig in the AWP Olmos Area.



Oil and gas sales from Swift's domestic properties in 2004 totaled $258.7 million, which was 83% of the Company's total sales. Capital expenditures related to domestic exploratory and development drilling were nearly $100 million in 2004 and are projected to be $150 million to $170 million in 2005.

LAKE WASHINGTON AREA

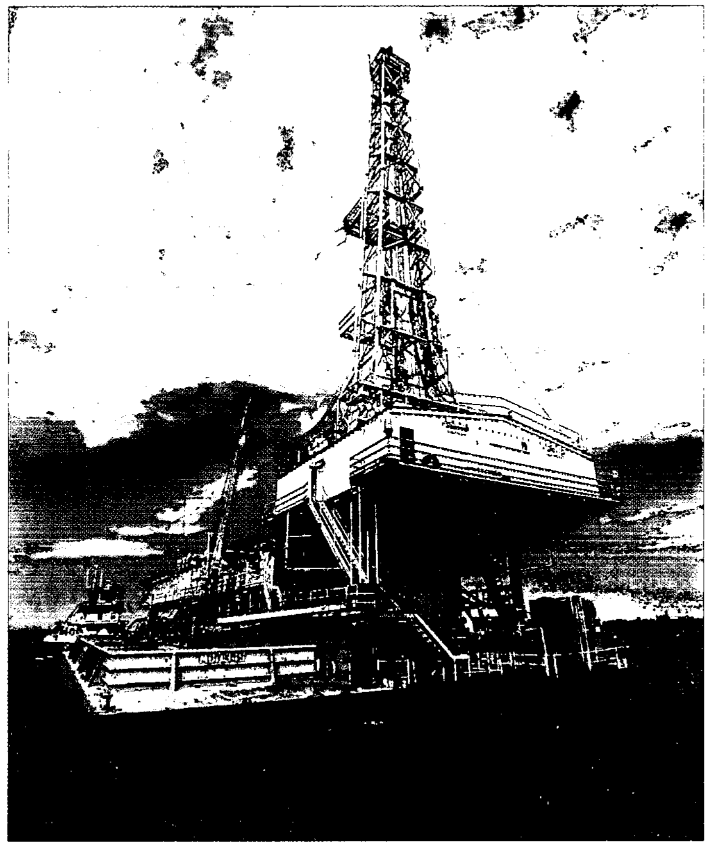
Swift Energy established the Lake Washington Area as its fourth domestic core area when it acquired majority interests in producing properties in the Lake Washington Field in early 2001. At the time of purchase, the properties, which lie in inland waters along the Louisiana Gulf coast, were producing less than 1,000 gross BOE per day. At year-end 2004, they were producing over 15,500 gross BOE per day, up from approximately 11,000 BOE per day during December 2003. The total Lake Washington production for 2004 was 3.8 million BOE, or 23.2 Bcfe, a 92% increase over the field's 2003 production.

Swift's proved reserves in Lake Washington have also greatly increased—from 7.7 MMBOE estimated at the time of purchase to 45.4 MMBOE (or 272.5 Bcfe) at year-end 2004, even after the Company had produced 40.9 Bcfe from the field since its acquisition. At year-end 2004, Lake Washington reserves comprised 42% of the Company's domestic proved reserves and 34% of its total proved reserves.

The Lake Washington Field, in which Swift holds 15,199 net acres, produces from multiple stacked Miocene sand layers radiating outward and downward from the surface of a centrally located salt dome. The surface depths of the salt dome vary from about 1,200 feet at its peak down to about 14,000 feet over most of Swift's acreage.

Because the field is heavily faulted, sections of the sand layers and the hydrocarbons they contain are trapped in multiple fault blocks (isolated reservoirs) around the dome. And because the field is primarily water driven, the hydrocarbons within the blocks tend to be pushed upward into the higher regions of the sand layers that lie closest to the salt dome, regions that are referred to as fault block "attics." Typically, each well drilled in a fault block is designed to intercept as many attics containing "pay sands" as possible.

Drilling is conducted with barge-based rigs positioned in the field's inland waters. Because most of the target fault blocks drilled by Swift to date have been adjacent to the dome, their attics have abutted the dome. In order to hit as many attics as possible, directional drilling has been employed. The hole is first drilled vertically down to target the uppermost attic and then is angled down the flank of the salt dome to penetrate other lower attics. If the area of the block is no more than 5 to 15 acres, drilling is generally limited to one well per block; however, for a large block, on the order of 100 to 120 acres, a successful well is usually followed by additional offset wells in order to drain as much as possible from the larger attic volumes or to reach attics not penetrated by the original well. To date, the depths of the wells drilled by Swift have generally ranged between 1,500 and 10,000 feet, the average being around 6,000 feet.



Drilling in the Lake Washington Field is conducted with rigs mounted on barges positioned in the inland waters.

As successful Lake Washington wells are completed for production, also from barge-based rigs, their casings are perforated at one or more of their deepest pay sands, with those at higher elevations kept behind pipe for perforations at later dates. All the wells are currently producing from only one sand zone, but many casings have sliding sleeves that allow the production to be switched to another zone where perforations exist. Subsequent perforations could allow a single well to produce from sequential zones for many years.

The well completion process includes procedures to prevent the influx of the formation sand through the perforations into the wellbore, which can disrupt production. In most wells to date, Swift has displaced the small-grain sand around the perforations with large-grain sand—known as installing gravel packs. In some recent wells, however, the Company has converted to "frac packing," a process that involves pumping the large-grain sand or other proppant out through the perforations and into the formation at rates and pressures exceeding the pressure required to fracture the formation. The sand deposited within the fractures, plus a high concentration of sand near the wellbore, then provides pathways that increase the oil flow into the wellbore. At the same time near-wellbore formation damage from drilling and completion is minimized.

The many Miocene sand layers slanting downward from the salt dome are mostly identified by letters of the alphabet, with others named for the depths at which they were first found. To date, Swift has encountered 70 different pay zones in the Lake Washington sands and has made completions in 33 pay zones, with an average of 148 feet of net pay per completed well.

Through 2004, Swift had drilled 120 Lake Washington wells with a 78% success rate. The 2004 drilling program consisted of 30 wells with a 70% success rate—23 development wells with 19 completions and seven exploration wells with two completions. For most of the year, the Company operated only one drilling rig in the field because of the on-going seismic survey, but in the fourth quarter three drilling rigs were briefly deployed.

Swift's Lake Washington drilling program has continued to include various locations around the salt dome, with wells completed in the F sand generally being the highest producers. As reported in earlier years, the F sand was not known to be productive in this area before Swift drilled the 2002 Cockrell-Moran #187, a development well that was deviated down the north flank of the dome and found pay in the F sand at a depth of 4,278 feet. The well initially produced 1,200 barrels per day and at year-end 2004 was still producing about 700 barrels of oil plus 160 Mcf of natural gas per day, with cumulative production of approximately 706,000 barrels of oil and 101 MMcf of gas.

Another 2002 development well, the SL-212#104 well that discovered the 8,400-foot sand on the northwest side of the dome, has also remained a consistent producer. At year-end 2004, it was still producing 800 barrels of oil per day and also producing 600 Mcf of natural gas per day. Its cumulative production at year-end 2004 was 496,000 barrels of oil and 439 MMcf of gas.

The field's two highest producers drilled in 2004 were both completed in the F sand on the north side of the dome. One was the CM-221 development well, which was drilled in May and at year-end was producing over 1,000 barrels per day. The other was the CM-268 development well, which was drilled in August and was producing over 980 barrels per day at year-end. The CM-268 found 379 feet of net pay in nine different sands.

The Lake Washington Field's Oil Delivery System platform is equipped with tank batteries for temporary storage of oil prior to shipping.

Additional F sand producers were also drilled on the north side of the dome during 2004, one of which, the CM-286, had 644 feet of net pay in eight different sands. On the northwest side of the dome, one successful well was drilled to the Li sand and another to the I sand.

Following the discovery of an all natural gas well in the shallow 2,000-foot sand during 2003, another gas well was completed in 2004. At year-end the BLDCM #18, a second-quarter development well drilled on the north side of the dome with 379 feet of total net pay in 10 different sands, was producing approximately 3 MMcf of gas per day in the SP-7 sand at a depth of about 7,900 feet. In addition, the SL-212 #132, a 2003 development well drilled on the northwest side of the dome, was producing approximately 1 MMcf per day from an upper region of the 6,500-foot exempt zone after earlier producing oil from a lower region.

The Lake Washington Area currently produces about 10.5 MMcf of gas per day, of which about 8.0 MMcf is marketed, with the remainder used as needed to maintain gas lift pressure for the oil wells and to operate equipment.

During assessments of its Lake Washington proved reserves in 2004, Swift engaged Integrated Reservoir Solutions Division of Core Laboratories to perform a reservoir analysis on the F sand on the north side of the salt dome. Their analysis of a whole core sample taken from the F sand in the CM-221 well showed that the volume percentage of oil in place was higher than previously assumed. As a result, the oil recovery factors for the F sand, used in reservoir calculations, will also be higher than for average sands. This type of information allows the Company to optimize primary and secondary reserves performance from high-quality reservoirs like the F sand. Current plans are to use the same procedure for optimization in other regions of the field and for other high-quality zones, particularly the D zone.

Locating and evaluating Lake Washington reserves was also a principal goal of a three-dimensional seismic survey conducted by Swift during the third quarter of 2004. Analysis of the data, which is under way, is expected to help identify targets for future exploratory drilling at depths of 10,000 feet and greater (see page 19). In the meantime, the data are being examined to enhance and expand the 2005 drilling inventory of intermediate targets (at 6,000- to 12,000-foot depths). They will also provide insights relative to reservoir management and future facility designs.

Swift's drilling inventory now includes approximately 98 drilling permits for both shallow and intermediate depths. Swift plans to drill at least 30 wells in the area in 2005, most at depths greater than 5,000 feet. Drilling to shallower targets is being deferred until the second half of the year because the CM-3 processing platform that removes hydrogen sulfide-bearing gas from the "sour" crude found in many of the shallow targets in the southern portion of the field is currently operating at or near capacity. Expansion of the capacity of the CM-3 platform up to 10,000 barrels per day is a near-term goal.

The field's other two processing platforms, the 212 platform and the 6700 platform, handle Swift's "sweet" crude production, and while their combined capacities are currently adequate, additional intrafield delivery systems are being installed to balance their loads. These systems, when combined with planned compression additions and infrastructure improvements in this area of the field, will allow the combined capacity of these two platforms—20,000 barrels per day—to be realized. The compression additions will also allow for the expansion of the gas lift system capacity, further increasing production capacity and efficiency. Additionally, potential improvements and additions to the gas treating system are being reviewed to help mitigate the downtime and reliability issues experienced with the treating unit in 2004.

Infrastructure improvements for processing of oil and gas and its delivery to market via pipeline or barge have comprised a large portion of Swift's Lake Washington operations since the property was acquired. During 2004, capital expenditures for facility upgrades in the field totaled approximately $13.5 million, with expenditures of about $25 million anticipated for 2005.

As the 2005 Lake Washington operation continues, it is anticipated that the analysis of the seismic survey data (see page 19) will confirm a number of prospects around the salt dome that have been developed by the Company's geologists for depth ranges of 7,000 to 14,000 feet. These and even deeper wells are expected to increasingly encounter high-pressure gas, which to date has been virtually untapped on Swift's acreage. The Company plans to begin drilling deep exploratory wells beginning in the last half of 2005 and to continue the program for the next three to four years.

AWP OLMOS AREA

The AWP Olmos Area in McMullen County, Texas, the oldest of Swift's current core areas of operations, was established in 1989 when the Company became the operator of approximately 65 producing natural gas wells located on a 4,900-acre leasehold position in the AWP Olmos Field.

The Company immediately began drilling additional wells to increase production from long-lived reserves held in the field's tight Olmos sand, each well having the potential to produce for 15 to 20 years.

To improve operations, Swift began focusing on the massive and costly process used to fracture the formation around the wells and induce gas flow into the wells. By varying the fracturing fluids and accompanying sands pumped down the wells and out into the formation, together with optimizing their injection rates, Swift cut fracturing costs dramatically while improving production.

The Company also found that performing two or more smaller fracture procedures separated in time was more effective for a new well than conducting a single large one. It followed that second fractures should also be performed on older wells for maximum production.

The Company also concentrated on various methods for increasing the upflow of gas in the wells, which was slowed by droplets of condensate carried in the flow stream falling back into the wells and blocking the flow (liquid loading). To minimize this problem, Swift began installing small-diameter (1-1/4-inch) coiled tubing in new wells as a lifting mechanism. The tubing restricted the cross section of the gas flow, increased its velocity, and prevented the fallback of the droplets. With the success of this technique, used for the first time in the AWP Field by Swift, the Company also began retrofitting older wells with the coiled tubing.

Distribution of Swift Energy's Proved Reserves
(as of December 31, 2004)

	Proved Reserves[a] (Bcfe)			Percent of Company's Reserves	Percent Natural Gas
	Developed	Undeveloped	Total		
Texas					
AWP Area	127.8	64.6	192.4	24.1%	69.0%
Brookeland Area	21.9	21.3	43.2	5.4%	43.5%
Other Texas	14.6	15.9	30.4	3.8%	90.7%
Total Texas	164.4	101.7	266.1	33.3%	67.3%
Louisiana					
Lake Washington Area	156.4	116.2	272.5	34.1%	8.5%
Masters Creek Area	24.3	30.2	54.5	6.8%	32.1%
Other Louisiana	6.0	37.4	43.4	5.4%	22.6%
Total Louisiana	186.7	183.7	370.4	46.3%	13.8%
Other States & Federal Offshore	9.2	7.0	16.2	2.0%	51.6%
Total Domestic	360.3	292.4	652.7	81.6%	36.8%
New Zealand					
Rimu/Kauri Area	46.2	61.9	108.1	13.5%	47.7%
TAWN Area	39.0	0.0	39.0	4.9%	73.7%
Total New Zealand	85.2	61.9	147.1	18.4%	54.6%
Total Company	445.5	354.3	799.8	100.0%	39.8%

[a] See definitions of proved reserves, proved developed reserves, and proved undeveloped reserves on page 72.

In 1994, the Company acquired an additional 8,830-acre leasehold position, adding other new leaseholds through 1996 and instituting an intensive drilling program. Additional improvements over the years included a reduction in operational costs with the adoption of slim-hole drilling techniques and remote operations to monitor production and perform other tasks. Although drilling in the area has been reduced in recent years, at year-end 2004 the AWP Area had 512 producing wells with Swift holding 100% working interests in almost all the wells. Of these, 13 producers were added in 2004 out of 15 wells drilled. In addition, four secondary fractures and four coiled-tubing installations were carried out on older wells.

Also in 2004, plunger lift was installed on 19 wells in the field that had previously been equipped with pumping units. On average, the switch in the lifting mechanism increased daily production by about 40 Mcf per day per well, at the same time reducing operating expenses by about $500 per well per month due to lower electricity use and less periodic workover expense.

At year-end, the AWP Olmos Area consisted of 27,534 net acres with proved reserves of 192.4 Bcfe, 29.5% of the Company's domestic reserves and 24.1% of its total reserves. Remaining undeveloped proved reserves totaled 64.6 Bcfe. AWP production during 2004 was 9.0 Bcfe, comprising 21.3% of Swift's domestic production and 15.4% of its total production.

Plans for the AWP Area in 2005 include drilling 12 to 15 wells and performing 15 fracture stimulations on wells that could benefit from additional stimulation.

MASTERS CREEK & BROOKELAND AREAS

Swift's operation of the Masters Creek Area and Brookeland Area began when the two areas were acquired together in mid-1998. They are located on opposite sides of the Texas-Louisiana boundary and both produce from the Austin Chalk trend, a formation in which natural vertical fractures can be filled with hydrocarbons and better intercepted by wells that are drilled in a horizontal direction. Horizontal wells are frequently drilled with two legs branching off in opposite directions from a single vertical hole, sometimes with more than one hydrocarbon deposit targeted in each leg. Typically successful Austin Chalk wells have high initial production as they drain the hydrocarbon pools and then decline relatively rapidly—that is, the reserves are short lived.

By the time Swift acquired these properties, the Company had already had six years of experience drilling over 85 Austin Chalk wells in the Texas Giddings Field with an 84% success rate. The Brookeland Field, located in Newton County and Jasper County, Texas, is similar to the Giddings Field in that both are depletion driven. The Masters Creek Field, located in Rapides Parish and Vernon Parish, Louisiana, differs in that it is water driven.

As is typical of Swift's operation, both fields were rapidly upgraded and intensive drilling programs were undertaken soon after their acquisition. As a result, the volumes of proven reserves increased dramatically and the fields have made significant contributions to the Company's production. With Swift's emphasis on long-lived reserves, no drilling occurred in these fields in 2002 and only one well was drilled in the Brookeland Area in 2003.

During 2004, one dual-lateral well was completed in Vernon Parish in the Masters Creek Area. During 2005, Swift expects to drill two to three development wells in Newton County in the Brookeland Area as re-entries of previously drilled wells.

At year-end 2004, Swift's interests covered 48,810 net acres in Masters Creek holding 54.5 Bcfe of proved reserves (with 30.2 Bcfe undeveloped) and 79,040 net acres in Brookeland holding 43.2 Bcfe of proved reserves (with 21.3 Bcfe undeveloped).

During 2004, Masters Creek contributed 3.7 Bcfe to Swift's total production (6.4%) and Brookeland contributed 3.4 Bcfe (5.9%).

Distribution of Wells in Which Swift Owned Interests

(as of December 31, 2004)

	Wells Operated by Swift[a]	Wells Operated by Others	Total Wells[a]	Percent of Swift's Year-end Proved Reserves	Percent of Swift's 2004 Production
Texas					
AWP Area	512	0	512	24.1%	15.4%
Brookeland Area	62	29	91	5.4%	5.9%
Other Texas	24	29	53	3.8%	2.9%
Total Texas	598	58	656	33.3%	24.2%
Louisiana					
Lake Washington Area	112	8	120	34.1%	39.8%
Masters Creek Area	81	25	106	6.8%	6.4%
Other Louisiana	26	5	31	5.4%	0.7%
Total Louisiana	219	38	257	46.3%	46.9%
Other States & Federal Offshore	7	14	21	2.0%	1.0%
Total Domestic	824	110	934	81.6%	72.1%
New Zealand					
Rimu/Kauri Area	19	0	19	13.5%	18.9%
TAWN Area	19	0	19	4.9%	9.0%
Total New Zealand	38	0	38	18.4%	27.9%
Total Company	862	110	972	100.0%	100.0%
Percent of Reserves	97%	3%			
Percent of Production	96%	4%			

[a] Swift is the operator of 835 producing wells and 27 service wells. The Company has interests in 932 producing wells and 40 service wells.

20 years

NEW ZEALAND CORE AREAS

Focusing on Quality Properties

To add an international component to its long-term growth strategy, Swift considered several global prospects and in the mid-1990s chose New Zealand, a land of political and economic stability with oil and gas exploitation potential. By 2004, Swift was the nation's most active driller, top holder of its onshore exploration acreage, and owner of a strategic portion of its petroleum industry infrastructure from wellhead to marketplace.

New Zealand's attributes include a dependable legal system, a reasonable tax structure, and excellent royalty terms for oil and gas production. Equally important for Swift, the country has established markets for oil and natural gas while its in-ground resources are relatively under-exploited. New Zealand's first oil well was drilled in 1865, just six years after the first U.S. oil well was drilled, but its oil and gas resources are far less developed than U.S. resources. Approximately 700 wells have been drilled in New Zealand in all its history, compared to more than 200,000 wells operating in Texas at year-end 2003. With its natural gas production forecast to be nearing a period of decline, the New Zealand government has recently enacted financial incentives for further exploration.

1995	Swift Energy International Inc. (SEI) established.
1995	Swift's first New Zealand petroleum exploration permit awarded.
1997	Swift Energy New Zealand Limited (SENZ) formed.
1999	Successful Rimu-A1 discovery well announced.
2002	TAWN Area acquired.
2002	Rimu Production Station completed.
2002	Commercial production from New Zealand begun.
2004	New Zealand held 18% of Swift's year-end reserves and provided 28% of year's production.

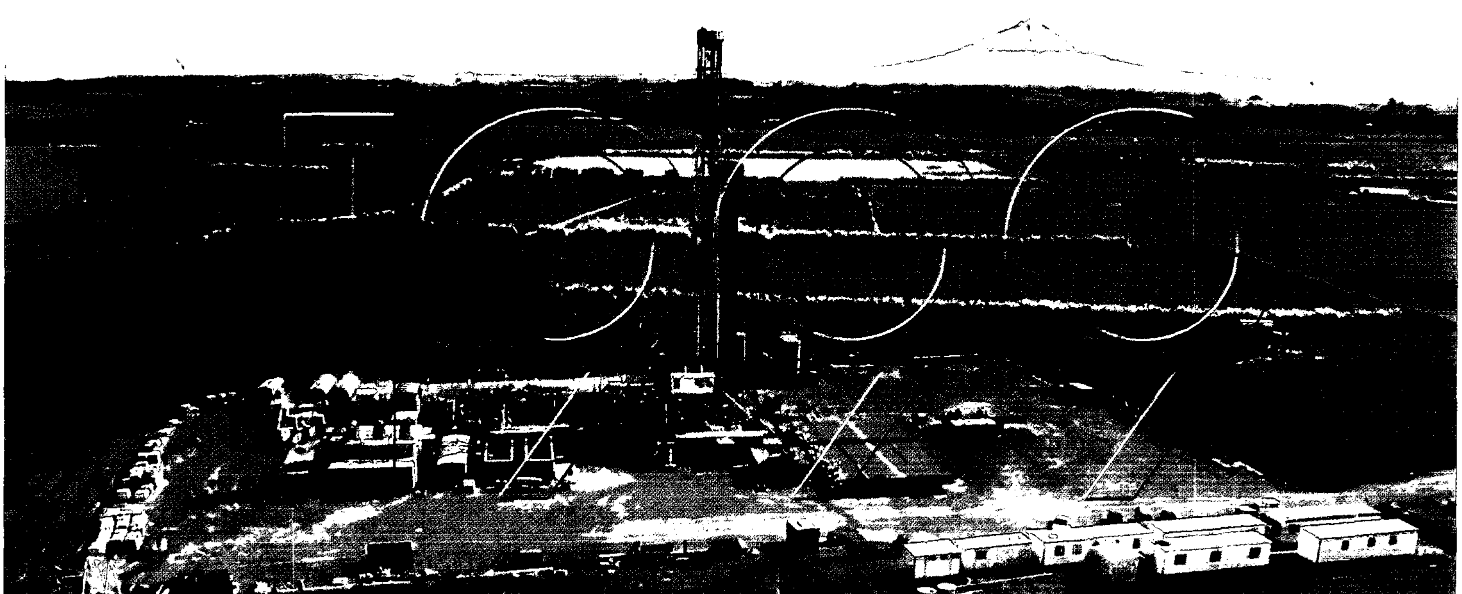
To date, Swift has established two core areas of operation in New Zealand under the nation's favorable permitting regime in which a petroleum exploration permit (PEP) is exclusive for five years with a five-year renewal allowed and a petroleum mining permit (PMP) is exclusive for up to 40 years. Identified as the TAWN Area and the Rimu/Kauri Area, the two properties are located just 17 miles apart in the Taranaki Basin on the north island. According to the most recent data available, they jointly supply approximately 8% of New Zealand's natural gas production and 6% of its oil production.

Swift's New Zealand properties provided $52.6 million in oil and gas sales in 2004, which was 17% of the Company's total sales for the year and was up 12% from 2003 levels. The increase was attributable to higher oil and gas prices, with Swift receiving an average composite price of $3.24 per Mcfe in New Zealand in 2004, up 34% over previous year prices. This price appreciation was due to several factors, including a favorable exchange rate, increased world demand for oil, and an expected tightening of New Zealand natural gas supplies.

Swift's production from its New Zealand operations in 2004 was 16.3 Bcfe, comprising 28% of the Company's total production. New Zealand provided nearly half (48%) of the Company's total natural gas production, 10% of its oil production, and 34% of its natural gas liquids (NGL) production, with controllable production costs of $0.68 per Mcfe.

The New Zealand production was 16% lower than in 2003, primarily

Below: Swift's 1999 Rimu A-1 discovery well.



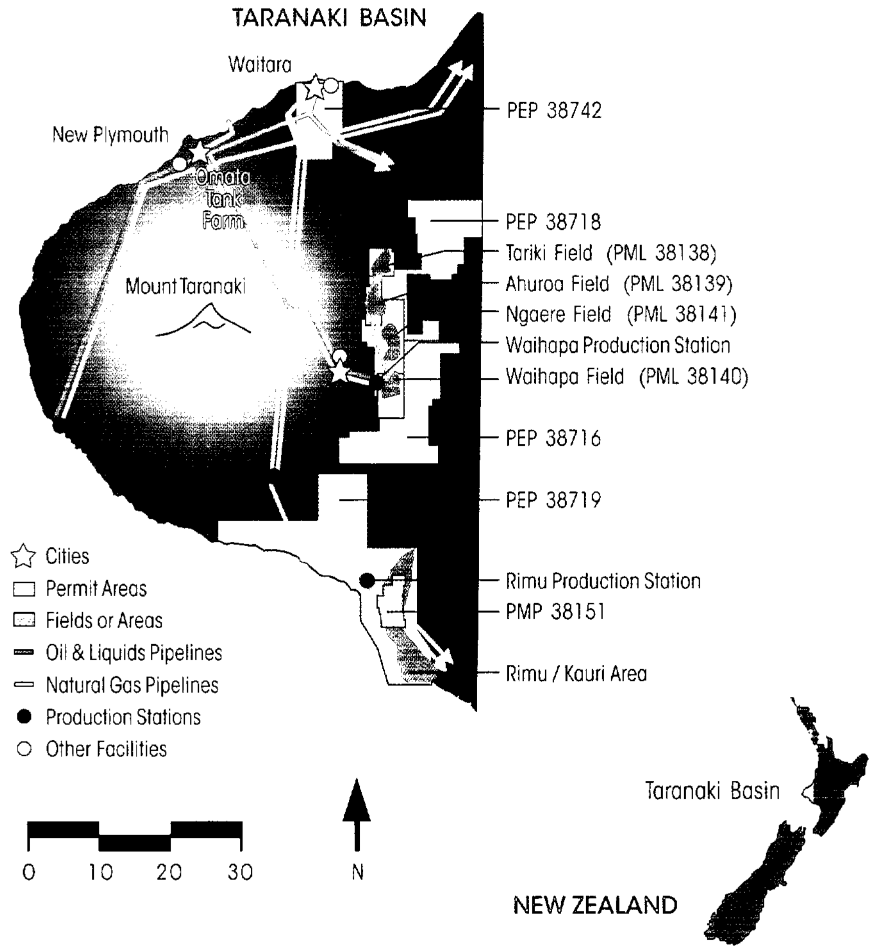
due to the natural decline in gas production from the TAWN Area. Swift's New Zealand natural gas production fell 20% from 14.3 Bcf in 2003 to 11.4 Bcf in 2004, and oil production decreased 21% from 572,683 barrels in 2003 to 452,753 barrels in 2004. However, the decline in oil production was partially offset by an increase in NGL production, with the New Zealand properties producing 350,303 barrels of natural gas liquids in 2004, up 24% from 283,227 barrels in 2003.

Swift's New Zealand reserves at year-end 2004 totaled 147.1 Bcfe, which was 16% lower than year-end 2003 levels primarily because drilling during the year was focused almost entirely on development drilling and thus no gains were realized from exploratory drilling in 2004.

In addition, downward revisions of reserves occurred in the Tariki and Manutahi sands in the Rimu/Kauri Area.

New Zealand reserves comprised 18.4% of the Company's total year-end proved reserves with 13.5% of total reserves attributable to the Rimu/Kauri Area and 4.9% to the TAWN Area. They consisted of 55% natural gas, 35% crude oil and 10% NGLs. Approximately 42% of Swift's New Zealand proved reserves are categorized as undeveloped and are in the Rimu/Kauri Area.

New Zealand Permit Areas with Swift-Owned Interests



TAWN AREA

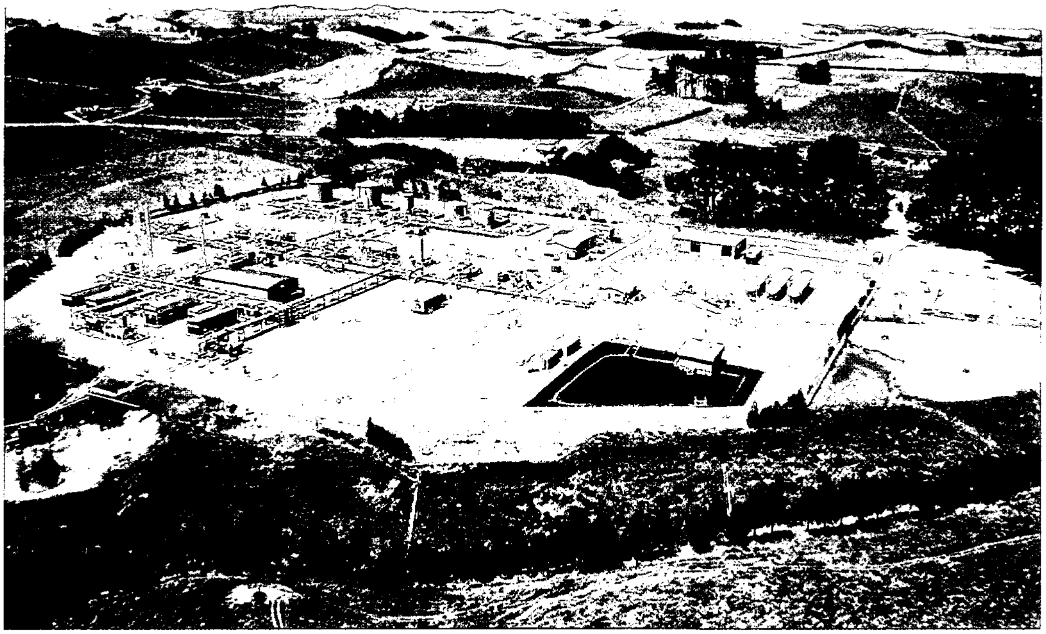
The TAWN Area consists of four producing fields that Swift acquired in 2002. Located less than 20 miles north of Swift's Rimu/Kauri Area, the area derives its name from the first letters of the four field names—the Tariki Field, the Ahuroa Field, the Waihapa Field, and the Ngaere Field. The Tariki and Ahuroa fields produce from the Tariki formation, and the Waihapa and Ngaere fields produce from the Tikorangi formation. Swift owns 100% of the working interests in the four petroleum mining licenses covering these fields.

In the fourth quarter of 2004, Swift drilled its first well in the TAWN Area, the Tariki-D1 development well. The well was drilled to a depth of 8,570 feet and was completed in the Tariki sands. In early 2005, the well was undergoing a long-term production test with initial flow rates of approximately 1.0 MMcf per day and 280 barrels of liquid per day with further testing scheduled.

The TAWN Area produced 11.0 Bcfe in 2004, comprising 19% of Swift's total production for the year. Natural gas production from the TAWN properties totaled 8.3 Bcf (35% of Swift's total natural gas production). Production from TAWN was down 32% in 2004 as compared to 2003 primarily because of production decline rates in the Tariki Field and Ahuroa Field.

Swift's infrastructure in the TAWN Area includes two processing plants and pipelines that deliver production to markets. The two processing facilities, the Waihapa Oil Plant and the Tariki Ahuroa Gas Plant, are both located at the Waihapa Production Station. In 2004, Swift doubled the gas plant's capacity for extracting and processing liquid petroleum gases, allowing the plant's production of liquid petroleum gases to increase 21% to 288,000 barrels in 2004, up from 238,000 barrels in 2003, despite the reduction in total natural gas processed at the plant in 2004. The gas plant also processes the solution gas captured at the oil facility.

At year-end 2004, the combined capacity of these two processing facilities was 15,000 barrels of oil and condensate per day and approximately 40 MMcf of gas per day, with the ability to further significantly increase natural gas processing with additional compression.



The TAWN Area's Waihapa Production Station consists of the Waihapa Oil Plant and the Tariki Ahuroa Gas Plant, with a combined capacity of 15,000 barrels of oil and condensate per day and approximately 40 MMcf of natural gas per day. In 2004, Swift Energy doubled the gas plant's capacity for extracting and processing liquid petroleum gases.

At year-end 2004, Swift's reserves in the TAWN Area totaled 39.0 Bcfe, representing 5% of Swift's total oil and gas reserves and 27% of its New Zealand reserves. Swift's TAWN reserves are 74% natural gas.

Swift plans to drill two exploration wells in the TAWN Area in 2005, the Goss A-1 located in PMP 38140 and the Trapper A-1 located in PMP 38141 (see page 20 for details).

RIMU / KAURI AREA

Located in close proximity to Swift's TAWN Area, the Rimu/Kauri Area was the main focus of Swift's 2004 drilling program in New Zealand and will remain so in 2005. Swift's primary targets in this field are the shallow Manutahi sand, the intermediate-depth Kauri sands, and the deep Tariki sands, all of which are located in PEP 38719.

The Manutahi sand, which Swift discovered in 2001 when drilling the Kauri-A1 exploratory well, is a shallow oil-producing sand with some properties similar to that of the Miocene sands targeted by Swift in its Lake Washington property.

In 2004, Swift completed a six-well drilling program in the Manutahi sand, with five successful development wells, of which one was later deemed noncommercial, and one unsuccessful exploratory well. For the six-month period from July through December 2004, the average total production of all the Manutahi development wells, including a successful 2003 well (the Kauri-F1), was 300 barrels of oil per day. Swift plans to drill four to six development wells to the Manutahi sand in 2005.

The Kauri sands, which Swift also discovered with the drilling of the Kauri-A1 well, are of low permeability, much like that of Swift's AWP Field in South Texas but with much greater complexity and variation within the formation. Swift first began production from the Kauri sands in mid-July 2003 following the successful fracture stimulation of the Kauri-A4 exploration well drilled in 2002. In 2003, another well, the Kauri-E2, was added to production.

During the first half of 2004, Swift drilled three more development wells to the Kauri sands from the Kauri-E pad (the Kauri-E3, -E4, and -E5 wells). Because of the sands' history of formation damage, Swift fine-tuned the individual fracture stimulations of the three wells by tailoring the composition of the fluid, the type of proppants, and the rate of pressure used. These modifications were based on the Company's study of well completion techniques and on its analysis of log data gathered from detailed step-rate production tests. The Kauri-E4 and -E5 wells, both completed using these modified fracture stimulation techniques, yielded test rates in late 2004 that were approximately double what was seen in earlier Kauri wells. As of January 2005, the two wells, which were drilled to a vertical depth of approximately 9,900 feet and are located less than four miles from Swift's Rimu-A1 discovery well, continued to produce 16 MMcf of natural gas and more than 800 barrels of condensate and oil per day. The fracture stimulation of the Kauri-E3 well was unsuccessful.

Swift also drilled the Kauri-E6 and -E7 development wells in the third and fourth quarters of 2004, respectively. Both wells are under consideration for fracture stimulations in the first half of 2005. The Kauri-E8, drilled in early 2005, was plugged and abandoned.

Swift's 2005 drilling program includes the drilling of three to four more wells to the Kauri sands, which appear to be a substantial gas-condensate producing formation.

Of the wells the Company has drilled to the deeper Tariki sands, which include upper and lower sandstone formations, its Rimu-A1 discovery well drilled in 1999 and Rimu-A3 development well drilled in 2001 continue to produce, with the Rimu-A1 producing at an average rate of 178 barrels of oil and 0.8 MMcf of natural gas per day. During 2004, the Kauri-E4 was taken down to the Tariki sands and produced from them briefly before being plugged back to the Kauri sands. In addition, the Kauri-E6 well was drilled to the Tariki sands and also was plugged back to the Kauri sands after encountering a limited Tariki reservoir. This well will be completed in the Kauri sands in 2005. Additional drilling to the Tariki sands in 2005 is under study, with a seismic survey planned in the Rimu/Kauri Area for identifying future drilling locations (see page 20 for details).

The Rimu/Kauri Area produced 5.3 Bcfe in 2004, contributing 9% of Swift's total production. Except for the Manutahi oil production, which is trucked from the area, Swift's production from the Rimu/Kauri Area is processed at the Company's Rimu Production Station. In 2004, Swift doubled the natural gas processing capacity at the Rimu facility from 10 MMcf to 20 MMcf per day. Because Swift had designed the plant so that capacity could easily be expanded, capital expenditures for this expansion were minimal. This increase in processing capacity was needed as the additional Kauri-E wells were brought into production. In January 2004, the monthly average rate of natural gas being processed at the plant was 5.9 MMcf per day, with a peak rate of 6.6 MMcf per day; by December 2004, it was 17.7 MMcf per day, with a peak rate of 20.1 MMcf per day. For oil, the Rimu Production Station's processing capacity was 7,500 barrels per day at year-end 2004.

Swift is evaluating the Rimu Production Station for a further 50% to 100% expansion of its gas processing capacity. In the meantime, the Company is installing equipment that will increase production capacity by 10% to 15% during 2005. It also is pursuing modifications of the pipeline system, which is owned by a third party, to resolve seasonal natural gas transmission constraints.

The pricing environment for natural gas in New Zealand is expected to remain firm as production from the Maui Field, which has been the primary supplier of New Zealand's natural gas, declines and the demand for natural gas increases. In recent years natural gas has supplied 20% to 30% of the nation's electricity needs, and in total energy consumption natural gas is the second largest energy source consumed, trailing oil slightly.

The market environment in New Zealand in 2004 allowed Swift to make additional natural gas sales above minimum contract amounts and to suspend some existing sales contracts in favor of higher prices. Natural gas processed at Swift's Rimu Production Station is sold to Genesis Power Limited, a state-owned power company, and natural gas processed at Swift's TAWN facilities is sold to Contact Energy Limited.

Oil production from both of Swift's New Zealand properties is generally sold under short-term contracts lasting one year or less, using a reference price of APPI (Asian Petroleum Price Index) Tapis, an internationally recognized crude oil index that is quoted at least weekly. The price is adjusted for various fees and premiums.

As New Zealand enters a period of declining production from the nation's major natural gas field, Swift is in a key position to expand its two core areas in the Taranaki Basin. With leasehold rights covering 132,578 undeveloped net acres in New Zealand, Swift is also in the position to develop a new core area outside of Rimu/Kauri and TAWN. See page 20 for discussion of Swift's future growth opportunities in New Zealand.

Swift's year-end proved reserves in the Rimu/Kauri Area totaled 108.1 Bcfe, representing 14% of Swift's total oil and gas reserves and 73% of its New Zealand reserves. Swift's Rimu/Kauri reserves are 48% natural gas.

MARKETING & OUTLOOK

Energy prices again rose appreciably in New Zealand in 2004, as they did in 2003. Swift's natural gas sales in New Zealand were also favorably impacted by New Zealand's government royalties as compared to the U.S. equivalent. For the TAWN Area, Swift pays a 10% royalty on net sales revenues. For the Rimu/Kauri Area, Swift pays a 5% ad valorem royalty. In comparison, in the United States Swift's production is typically covered by both severance and ad valorem taxes of 9% to 12.5% in addition to landowner royalties of 12.5% to 30%.

Swift Energy placed the Rimu Production Station in operation in 2002 and doubled its natural gas processing capacity from 10 to 20 MMcf per day in 2004. The increase was needed to accommodate additional production from Kauri wells, which by year-end 2004 had increased to an average of 17.7 MMcf per day with a peak rate of 20.1 MMcf per day.

25 years

FINANCIAL FLEXIBILITY

Enhancing Value and Managing Risk

Throughout its history, Swift Energy has practiced a *disciplined approach to financial management.* At the center is a strong capital structure that balances equity and debt and preserves the Company's flexibility to adjust to the dynamics of a volatile industry.

Key components include strategically balancing the capital budget between drilling and acquisitions, matching long-lived assets with long-term financing, establishing leverage targets that are reasonable given the volatility of oil and gas prices, opportunistically accessing capital markets, continually improving the Company's credit profile, and effectively managing risk.

Rising oil and gas prices coupled with Swift's production increases enabled the Company to expand its capital budget in 2004 from a projected range of $130 million to $150 million to capital expenditures of $192 million. Net cash provided by operating activities rose 65% to $182.6 million, and cash flow per diluted share rose 60% to $6.44 in 2004. Cash flows covered the majority of Swift's budget *expenditures for the year, allowing the Company to pursue* its objectives without significantly using its credit facility. EBITDA (see Glossary on page 71) was $211 million for 2004, an increase of 49% over 2003. Swift's 10-year compounded annual growth rate for EBITDA is 30%.

Swift continued to maintain its strong liquidity position in 2004, with an outstanding balance of $7.5 million drawn on its $400 million revolving line of credit at year-end. This credit facility, which has been extended through October 2008, has a commitment amount set at $150 million at Swift's request and has a borrowing base of $250 million. At the end of 2003, the Company had an outstanding balance of $15.9 million drawn on its $300 million revolving line of credit.

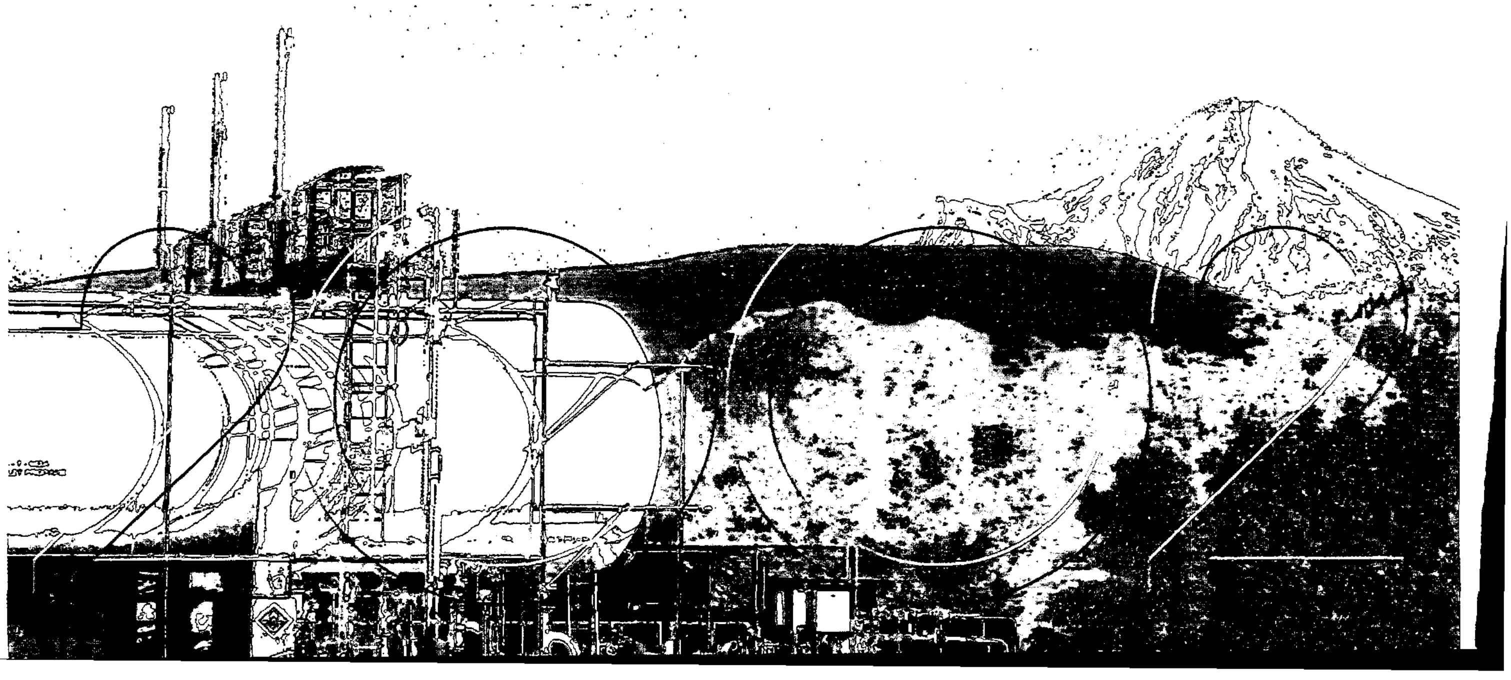
As part of Swift's goal of maintaining financial discipline, the Company's debt to PV-10 ratio was 18% at year-end 2004, compared to 22% in 2003 and 28% in 2002. Working capital totaled a negative $14.2 million at year-end 2004, compared to a negative $35.9 million at year-end 2003.

In mid-year 2004, Swift refinanced a portion of its long-term debt to reduce interest expense. Using proceeds from the issuance of $150 million of new 7-5/8% senior notes due 2011, Swift redeemed $125 million of outstanding 10-1/4% senior subordinated notes due 2009.

Swift projects that its capital budget for 2005 will range between $200 million and $220 million, with internally generated cash flows expected to

1995	Sale of 5.75 million shares of common stock allowed transition away from limited partnership financing.
1999	Swift issued $125 million of 10-1/4% senior notes due 2009.
2002	Swift issued $200 million of 9-3/8% senior subordinated notes due 2012.
2002	Last public limited partnerships liquidated.
2004	Swift redeemed $125 million of 10-1/4% senior notes due 2009.
2004	$150 million of 7-5/8% senior notes due 2011 offered to public.
2004	Revolving credit facility renewed and extended with facility increased to $400 million.

Below: Financial flexibility allows Swift to pursue strategic opportunities as they arise, such as the acquisition of the TAWN Area in 2002.



fund the majority of expenditures. Factors that could affect Swift's ability to generate expected cash flows include production levels and oil and gas prices.

At year-end 2004, Swift also had available for further financing, if needed, $242.5 million under its revolving line of credit and the ability to offer up to $200 million of securities under its universal shelf registration, which became effective in April 2004.

As has been its strategy for several years, Swift focuses its price risk management strategy on realizing the full benefit of high commodity prices during periods of upswings while protecting against serious downturns. Swift's exposure to volatile commodity prices—which are inherent in the oil and natural gas industry—is the Company's major market risk.

Overseen by the Finance Committee chaired by the Company's president, and reviewed by its chief executive officer, the Company's price risk management program accomplishes its hedging strategy through the use of floors, near-term forward sales, and participating costless collars.

Some 20% to 50% of the Company's volume of oil and U.S. natural gas production is typically targeted for coverage, with hedging implemented when market prices are strong. This strategy protects near-term cash flows and the capital budget while maintaining upside potential.

In New Zealand, long-term contracts are used for price risk management of natural gas.

25 years

LEADERSHIP & MANAGEMENT

Continuing 25 Years of Teamwork

For the past quarter of a century, the cornerstone of Swift Energy's success in a volatile industry has been its seasoned leadership. Many of the Company's leaders have worked together for a decade or more, forming a flexible and knowledgeable management team that is able to respond quickly and competently to industry changes.

This veteran leadership, combined with an experienced and competent board of directors and effective mechanisms of corporate control, has been key to Swift's long-term success.

MANAGEMENT TEAM

In making appointments to its management team in 2004, Swift continued its policy of promoting from within employees who have been

Chairman, 1979 – A. Earl Swift, founder of Company. President until 1997 and chief executive officer until 2001.
Vice Chairman, 1981 – Virgil N. Swift. Executive vice president 1982-2000; chief operating officer 1982-1991. Chairman of Swift Energy International since 1995.
Chief Executive Officer, 2001 – Terry E. Swift. Director since 2000. Formerly executive vice president, president, and chief operating officer.
President, 2004 – Bruce H. Vincent. Also secretary since 2000, and president of Swift Energy International since 2004. Formerly executive vice president for corporate development.
Chief Operating Officer, 2000 – Joseph A. D'Amico. Executive vice president since 2000. Formerly senior vice president for exploration and development.
Chief Financial Officer, 2000 – Alton D. Heckaman, Jr. Appointed executive vice president in 2004. Formerly senior vice president and controller.

Below: A. Earl Swift marks the Company's 25th anniversary by ringing the closing bell at the New York Stock Exchange in November 2004.

instrumental in past successes and recruiting new staff with exemplary industry experience in areas critical to the Company's future plans for growth.

In this tradition, Bruce H. Vincent, who has been with the Company for 15 years, was named president of Swift Energy in November 2004. He also continues to serve as corporate secretary, a position he assumed in August 2000, and as president of Swift's wholly owned subsidiary, Swift Energy International, Inc., a position he assumed in February 2004. Mr. Vincent served in several strategic positions prior to his latest promotion, most recently as executive vice president-corporate development.

Other key appointments made to Swift's management team in November 2004 included the promotion of Alton D. Heckaman, Jr., to executive vice president from senior vice president-finance. Mr. Heckaman, who has been with the Company for 23 years, also continues to serve as chief financial officer.

Victor R. Moran, who has been with the Company for 13 years, was named senior vice president and chief compliance officer. Mr. Moran's most recent position within the Company was senior vice president-energy marketing and business development.

In February 2004, Robert J. Banks was appointed vice president-international operations of Swift's wholly owned subsidiary, Swift Energy International, Inc. Mr. Banks is based at Swift's Houston office, serving as a liaison between Swift's U.S. headquarters and its international operations, currently focusing in New Zealand. He joined Swift with more than 25 years of oil and gas industry experience, with his most recent work focused on international operations involving exploration, production, and project development in several countries, including New Zealand.

In December 2004, Swift appointed Laurent "Larry" A. Baillargeon as the Company's general counsel. Mr. Baillargeon, who has been with Swift for five years, previously served as general counsel-exploration and production. He has 29 years of legal background in oil and gas, including exploration and production activities, land and legal contracts, and acquisitions and divestitures. Prior to joining Swift, Mr. Baillargeon held legal positions with various oil and gas companies from independents to majors.

D. Wynn Ibach, Swift's former general counsel, is now "Of Counsel" to the Company.

ACCOUNTABILITY CONTROLS

Long before the nation's recent emphasis on corporate accountability with the passage of the Sarbanes-Oxley Act in 2002, Swift had controls in place that exemplify the Company's belief in openness and ethical conduct.

For many years, the majority of Swift's Board of Directors has been comprised of outside independent directors. In May 2004, the board welcomed new outside director Deanna L. Cannon, president of Cannon & Company CPA's PLC, a privately held consulting firm in Traverse City, Michigan. Ms. Cannon previously served as chief financial officer of Miller Exploration Company, a publicly held independent oil and gas exploration and production company that was acquired by Edge Petroleum Corporation.

Internally, Swift's corporate controls begin with its five-year strategic plan, which is closely intertwined with the control environment created by management. A review of the Company's progress in fulfilling its strategic plan is presented to the Board of Directors each year.

The strategic plan's implementation begins with the budgeting process, which is overseen by a committee chaired by the chief operating officer and comprised of representatives from appropriate contributing departments. The Budget Committee—with input from the entire executive management team—sets the direction of the budgeting process by determining the basic parameters that will guide the development of each department's annual budget.

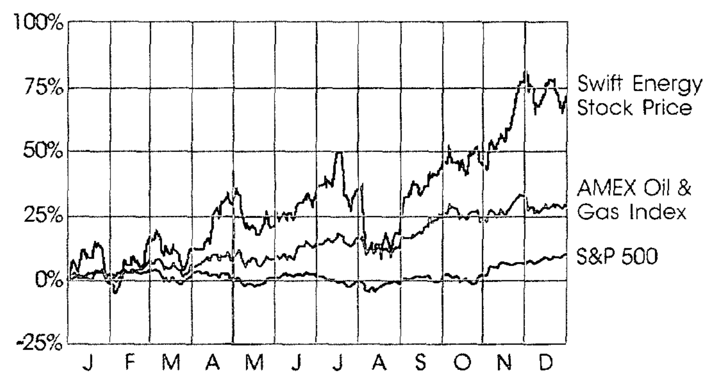
The Budget Committee creates capital expenditure scenarios and financial outlooks using project rankings created by various asset teams. Ultimately, the committee presents its top scenarios to the board for final consideration, and during the fourth quarter of each year, the board approves one scenario as the consolidated budget for the following year. Once a budget is approved, individual projects within the budget undergo an "authority for expenditure" (AFE) approval process that includes both operating and financial reviews.

Altogether, the AFE approval process, the annual budget, and the strategic plan help set the Company's basic direction and tone and assist in structuring many of Swift's major expenditure controls.

General information about Swift's corporate governance is available in the corporate governance section of the Company's web site.

Daily Year-to-Date Percentage Changes in Swift Energy's Closing Stock Price

January - December 2004



Sources: NYSE, AMEX, and S&P

FUTURE GROWTH OPPORTUNITIES

Heading Toward a Bright Future

As Swift Energy continues to exploit its current core areas of operation, it also seeks other properties, through exploration or acquisition, that have the potential for becoming new core areas. Criteria for new properties include long-term growth opportunities and a logical fit into the Company's overall operations. Locations of primary interest are along the Louisiana and Texas Gulf Coast and in New Zealand's Taranaki Basin. During 2004, Swift took steps toward establishing new core areas in both geographic areas.

SOUTH LOUISIANA

In view of its recent successes in the relatively shallow Miocene sands of the Lake Washington Field in Plaquemines Parish, Louisiana (see page 8), Swift has embarked upon a study of the field's deeper horizons. During 2004, the Company conducted a three-dimensional seismic survey over 55 square miles of the field with a focus on intermediate depths between 6,000 and 12,000 feet. Swift further acquired 550 square miles of three-dimensional seismic data for the area west of its acreage to merge with its own data. To aid in the analysis of the entire data base, the Company has engaged the services of a third-party consulting firm.

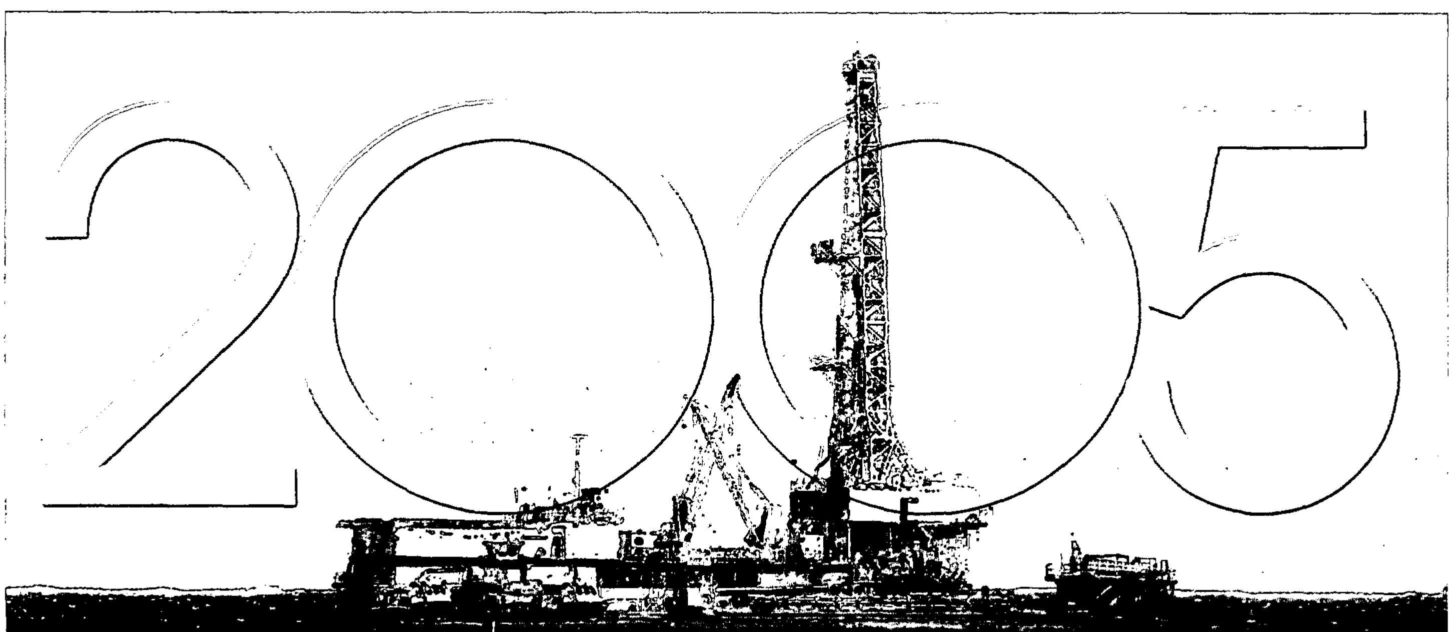
The resulting proprietary analysis not only will help Swift in more precisely identifying intermediate-depth targets for its 2005 Lake Washington drilling program, which will include four or more exploratory wells, but also will help in assessing deeper prospects that the Company's geologists and petrophysicists have developed around the salt dome. The Company anticipates that the deeper targets will most likely be natural gas.

In a related move, Swift has recently acquired two additional properties in South Louisiana. Purchased for $27.7 million, they consist of 100% working interests in two fields: the Bay de Chene Field (approximately 14,200 gross acres) located about 30 miles northwest of Lake Washington along the common boundary of Lafourche Parish and Jefferson Parish; and the Cote Blanche Island Field (approximately 6,200 gross acres) located about 100 miles west of Lake Washington in St. Mary Parish. Like Lake Washington, each field is located in inland waters over a salt dome and produces from multiple Miocene sand layers. Their combined estimated proved reserves were 5.6 million barrels of oil and 9.8 Bcfe of natural gas (or 7.3 million BOE), of which 9% were proved developed reserves. Over 80% of the value is in the Cote Blanche Island Field.

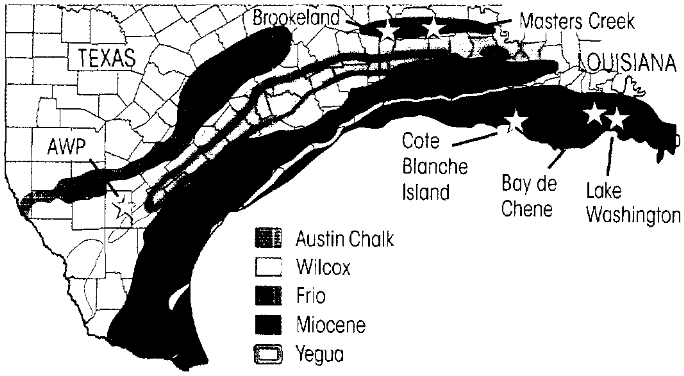
Each field has approximately 10 producing wells, numerous nonproducing wells, a centralized processing platform, and several tank batteries. Their combined current production is approximately 750 BOE per day, and Swift believes $50

2004	Future Growth Activities
February	Exploration in South Texas Frio sands continued.
June	Exploration in South Texas Wilcox sands continued.
August	3-D seismic data acquired for deep Miocene sands in Lake Washington.
December	Swift entered into farm-in agreement in New Zealand.
December	Swift acquired interests in the Cote Blanche Island Field and Bay de Chene Field in Louisiana.

Below: A drilling barge in the Lake Washington Area. Swift acquired its initial interests in Lake Washington during March 2001.



Domestic Core Areas and Recent Acquisitions



million will be required to properly develop and exploit the fields' reserves. A multiyear development program will be initiated during the second half of 2005 with two to three wells drilled in each field before year-end.

Existing three-dimensional data over the Bay de Chene Field will be merged with the 550-square-mile data base recently acquired for the region west of Swift's Lake Washington acreage, and the Company is investigating acquiring three-dimensional data for the Cote Blanche Island Field. Swift may also conduct its own three-dimensional seismic surveys over both new areas.

SOUTH TEXAS

In its South Texas activities during 2004, Swift continued drilling to the Wilcox sands in Goliad County northeast of its AWP Olmos Area in McMullen County, Texas. Following successful wells on the Nita prospect in 2001 and 2003 (the Post #1 and #2), the Company completed two more development wells in the area during 2004—the Post #3 and #4, both at depths of about 12,900 feet. The Post #3, in which Swift has a 68% working interest, tested at 2,300 Mcf of gas and 8 barrels of condensate per day. The Post #4, in which Swift has a 61% working interest, tested at 2 MMcf and 20 barrels of condensate per day. The Company also completed another Wilcox development well, the Bravo Land #2, with a 69% working interest in Duval County directly south of AWP. It reached a depth of 9,898 feet and tested at rates up to 1,300 Mcf of gas and 20 barrels of condensate per day.

During 2005, the Company will focus on developing additional Wilcox prospects in a contiguous seven-county area northeast of AWP that includes Goliad County, plus the counties of Victoria, De Witt, Jackson, Lavaca, Wharton, and Colorado. Prospects in the Frio and Yegua formations in these counties will also be developed.

During 2004, the Company also continued drilling to the Frio formation in Garcia Ranch, a region southeast of AWP in Kenedy County and Willacy County. It completed one exploratory well in Kenedy County and participated in the completion of another in Willacy County. A nonoperated exploratory well and an operated development well in Willacy County were unsuccessful.

For 2005, Swift's tentative plans are to drill two exploratory and two development wells in the South Texas region.

NEW ZEALAND'S TARANAKI BASIN

During 2005, Swift will drill four exploration wells and participate in at least one nonoperated exploration well in New Zealand's Taranaki Basin.

Three wells will be drilled by Swift as part of a joint venture the Company entered into in early 2005 with Mighty River Power (MRP), a state-owned New Zealand utility that provides up to 22% of the country's electricity. One well is the Tawa prospect, which is located in the same petroleum exploration permit (PEP) area as the Rimu/Kauri Area (see PEP 38719 in map on page 13) and will be drilled in the third quarter of the year. Targeting multiple sands, including the Kauri sands, this prospect is a stratigraphic trap located on the flank of the prolific Kapuni Field and was developed on the basis of Swift's analysis of available two- and three-dimensional seismic data plus two-dimensional data acquired during Company surveys in 1997 and 2000.

The other two joint venture wells are located in the Company's TAWN Area. One is on the Goss prospect, also known as the Waihapa Deep prospect, located in petroleum mining license (PML) area 38140; the other is on the Trapper prospect located in PML 38141. The Trapper prospect combines two earlier prospects identified as the Toko Deep and Ahuroa Flank prospects. Both wells will have the Kapuni group sands (the major reservoir in the basin) as their main target, but they will also be drilled through the Tariki sandstone and other productive zones in the basin.

Swift also plans to participate in at least one nonoperated exploratory well targeting the Mt. Messenger formation in PEP 38716 with a 21.4% working interest.

In addition, the Company plans to conduct a 70-to 110-kilometer two-dimensional transitional zone seismic survey in the Rimu/Kauri Area (PEP 38719) that should help identify locations for a deep Tariki test (upper and lower plates) that would be along a trend with Swift's Rimu-A1 discovery well. This seismic survey will also help identify additional potential Kauri and Manutahi sand targets. Note that PEP 38719 now includes the two areas previously identified as PEP 38756 and PEP 38759.

Finally, Swift has entered into a farm-in agreement with Balance Agri-Nutrients Limited to drill in PEP 38742 in search of natural gas as replacement feedstock for that company's Kapuni urea manufacturing plant. Its first well, the Karaka A-1 drilled early in 2005 as a shallow test of the Mt. Messenger formation, was unsuccessful; however, other prospects will be matured through 2005.

SWIFT ENERGY OFFICERS

INCLUDES OFFICERS OF
SWIFT ENERGY INTERNATIONAL (SEI) AND
SWIFT ENERGY NEW ZEALAND (SENZ)

Terry E. Swift
Chief Executive Officer

Bruce H. Vincent
President & Secretary;
President, SEI

Joseph A. D'Amico
Executive Vice President
& Chief Operating Officer

Alton D. Heckaman, Jr.
Executive Vice President
& Chief Financial Officer

James M. Kitterman
Senior Vice President–
Operations

James P. Mitchell
Senior Vice President–
Commercial
Transactions & Land

Victor R. Moran
Senior Vice President &
Chief Compliance Officer;
Secretary, SEI

Gerald B. Long
Vice President–
Production Operations

Thomas E. Schmidt
Vice President–
Exploitation &
Development

Tara L. Seaman
Vice President–
Reserves & Evaluations

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

Laurent A. Baillargeon
General Counsel

Donald L. Morgan
Executive Vice President,
SEI; Chairman &
Chief Executive Officer,
SENZ

Robert J. Banks
Vice President–
International Operations,
SEI

R. Alan Cunningham
President & Chief
Operating Officer,
SENZ

Steven B. Yakle
Treasurer, SEI;
Vice President–Finance,
Chief Financial Officer,
Secretary, SENZ

Christopher J. T. Bush
Vice President–Facilities,
SENZ

BOARD OF DIRECTORS


A. Earl Swift
Chairman of the Board,
Age 71


Virgil N. Swift
Vice Chairman of the Board;
Chairman of Swift Energy
International,
Age 76


Terry E. Swift
Chief Executive Officer,
Age 49


Deanna L. Cannon
President,
Cannon & Company CPA's
PLC,
Age 44


G. Robert Evans
Retired Chairman & CEO,
Material Sciences
Corporation,
Age 73


Raymond E. Galvin
Retired President, Chevron
U.S.A. Production Company,
Age 73


Greg Matiuk
Retired Executive Vice President,
Administration & Corporate
Services, ChevronTexaco
Corporation,
Age 60


Henry C. Montgomery
Chairman & Founder,
Montgomery Professional
Services Corp.,
Age 69


Clyde W. Smith, Jr.
President,
Ascentron, Inc.,
Age 56


Raymond O. Loen
Director Emeritus,
Age 80

BOARD OF DIRECTORS COMMITTEES:

Audit Committee:
Henry C. Montgomery, Chairman,
Deanna L. Cannon, G. Robert Evans,
Clyde W. Smith, Jr.

Corporate Governance Committee:
G. Robert Evans, Chairman,
Deanna L. Cannon, Raymond E. Galvin,
Greg Matiuk

Compensation Committee:
Clyde W. Smith, Jr., Chairman,
Raymond E. Galvin, Greg Matiuk,
Henry C. Montgomery

Executive Committee:
A. Earl Swift, Chairman,
Virgil N. Swift, Terry E. Swift, Raymond E. Galvin

FINANCIAL REPORT

Selected Financial and Operating Data

	2004	2003	2002	2001
Total Revenues	$310,276,774	$208,900,983	$149,969,811	$183,807,490
Income (Loss) Before Income Taxes and Change in Accounting Principle[1]	$101,440,242	$50,739,178	$18,408,289	$(34,192,333)
Net Income (Loss)	$68,450,917	$29,893,812	$11,923,227	$(22,347,765)
Net Cash Provided by Operating Activities	$182,582,887	$110,827,279	$71,626,314	$139,884,255
Per Share Data				
Weighted Average Shares Outstanding[1]	27,822,413	27,357,579	26,382,906	24,732,099
Earnings (Loss) per Share—Basic[1]	$2.46	$1.09	$0.45	$(0.90)
Earnings (Loss) per Share—Diluted[1]	$2.41	$1.08	$0.45	$(0.90)
Shares Outstanding at Year-End	28,089,764	27,484,091	27,201,509	24,795,564
Book Value per Share at Year-End	$16.88	$14.46	$13.42	$12.61
Market Price[1]				
High	$30.34	$18.00	$20.58	$37.70
Low	$15.90	$7.60	$6.80	$16.66
Year-End Close	$28.94	$16.85	$9.67	$20.20
Effect on Net Income and Earnings per Share from Changes in Accounting Principles[2]				
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	—	$(4,376,852)	—	$(392,868)
Effect per Share—Basic	—	$(0.16)	—	$(0.01)
Effect per Share—Diluted	—	$(0.16)	—	$(0.01)
Assets				
Current Assets	$54,385,996	$33,460,957	$29,768,199	$36,752,980
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization	$923,438,160	$815,807,003	$721,617,941	$628,304,060
Total Assets	$990,573,147	$859,838,544	$767,005,859	$671,684,833
Liabilities				
Current Liabilities	$68,618,291	$69,353,342	$46,884,184	$73,245,335
Long-Term Debt	$357,500,000	$340,254,783	$324,271,973	$258,197,128
Total Liabilities	$516,401,007	$462,447,280	$401,932,675	$359,032,113
Stockholders' Equity	$474,172,140	$397,391,264	$365,073,184	$312,652,720
Number of Employees	272	241	234	209
Producing Wells				
Swift Operated	835	870	820	854
Outside Operated	97	128	112	381
Total Producing Wells	932	998	932	1,235
Wells Drilled (Gross)	66	75	36	53
Proved Reserves				
Natural Gas (Mcf)	318,246,294	335,804,862	326,731,672	324,912,125
Oil, NGL, & Condensate (barrels)	80,267,208	80,759,903	70,438,963	53,482,636
Total Proved Reserves (Mcf equivalent)	799,849,539	820,364,284	749,365,449	645,807,939
Production (Mcf equivalent)[3]	58,318,502	53,158,384	49,752,346	44,791,202
Average Sales Price				
Natural Gas (per Mcf)	$4.12	$3.42	$2.30	$4.23
Natural Gas Liquids (per barrel)[4]	$22.52	$17.60	$12.82	—
Oil (per barrel)[4]	$40.24	$29.89	$24.52	$22.64
Mcf Equivalent	$5.34	$3.97	$2.84	$4.05

[1]Amounts have been retroactively restated in all periods presented to give recognition to: (a) an equivalent change in capital structure as a result of two 10% stock dividends, one in September 1994, the other in October 1997; (b) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share," and (c) the adoption in 2003 of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," which affected our presentation of 1999 results by reclassifying the loss on early extinguishment of debt from an extraordinary item to an operating item.

[2]We adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003. We adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Transactions" on January 1, 2001. As of January 1, 1994, we changed our revenue recognition policy for earned interests.

[3]Natural gas production from 1994 to 2000 includes volumes under a production payment agreement ranging from 1.4 Bcfe in 1994 to 0.4 Bcfe in 2000.

[4]Prior to 2002, we combined NGLs with natural gas for reporting purposes.

2000	1999	1998	1997	1996	1995	1994
$191,624,946	$110,671,007	$82,469,221	$74,712,180	$56,298,026	$25,092,230	$21,624,231
$92,449,488	$29,736,151	$(73,391,581)	$33,129,606	$28,785,783	$6,894,537	$4,837,829
$59,184,008	$19,286,574	$(48,225,204)	$22,310,189	$19,025,450	$4,912,512	$(13,047,027)
$128,197,227	$73,603,426	$54,249,017	$55,255,965	$37,102,578	$14,376,463	$10,394,514
21,244,684	18,050,106	16,436,972	16,492,856	15,000,901	10,035,143	7,308,673
$2.79	$1.07	$(2.93)	$1.35	$1.27	$0.49	$(1.79)
$2.51	$1.07	$(2.93)	$1.26	$1.25	$0.49	$(1.79)
24,608,344	20,823,729	16,291,242	16,459,156	15,176,417	12,509,700	6,685,137
$13.50	$8.18	$6.71	$9.69	$9.41	$7.46	$6.30
$43.50	$13.31	$21.00	$34.20	$28.86	$11.48	$10.35
$9.75	$5.69	$6.94	$16.93	$9.89	$7.05	$7.75
$37.63	$11.50	$7.38	$21.06	$27.16	$10.91	$8.86
—	—	—	—	—	—	$(16,772,698)
—	—	—	—	—	—	$(2.52)
—	—	—	—	—	—	$(2.52)
$41,872,879	$50,605,488	$35,246,431	$29,981,786	$101,619,478	$43,380,454	$39,208,418
$524,052,828	$392,986,589	$356,711,711	$301,312,847	$200,010,375	$125,217,872	$88,415,612
$572,387,001	$454,299,414	$403,645,267	$339,115,390	$310,375,264	$175,252,707	$135,672,743
$64,324,771	$34,070,085	$31,415,054	$28,517,664	$32,915,616	$40,133,269	$52,345,859
$134,729,485	$239,068,423	$261,200,000	$122,915,000	$115,000,000	$28,750,000	$28,750,000
$240,232,846	$283,895,297	$294,282,628	$179,714,470	$167,613,654	$81,906,742	$93,545,612
$332,154,155	$170,404,117	$109,362,639	$159,400,920	$142,761,610	$93,345,965	$42,127,131
181	173	203	194	191	176	209
817	769	836	650	842	767	750
711	788	917	917	986	3,316	3,422
1,528	1,557	1,753	1,567	1,828	4,083	4,172
70	27	75	182	153	76	44
418,613,976	329,959,750	352,400,835	314,305,669	225,758,201	143,567,520	76,263,964
35,133,596	20,806,263	13,957,925	7,858,918	5,484,309	5,421,981	4,553,237
629,415,552	454,797,327	436,148,385	361,459,177	258,664,055	176,099,406	103,583,566
42,356,705	42,874,303	39,030,030	25,393,744	19,437,114	11,186,573	9,600,867
$4.24	$2.40	$2.08	$2.68	$2.57	$1.77	$1.93
—	—	—	—	—	—	—
$29.35	$16.75	$11.86	$17.59	$19.82	$15.66	$14.35
$4.47	$2.54	$2.05	$2.72	$2.71	$2.01	$2.06

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

The following discussion and analysis supplements and is provided to facilitate increased understanding of our 2004, 2003 and 2002 consolidated financial statements and our accompanying notes included with this report.

Overview

For 2004, we had revenues of $310.3 million and production of 58.3 Bcfe. Our revenues were bolstered by oil and gas prices remaining strong and our domestic production for 2004 increasing to 42.1 Bcfe or by 25% compared to 2003. We continued to focus our efforts and capital throughout the year on infrastructure improvements, increased production and the development of long-lived reserves in the Lake Washington and AWP Olmos areas. Our net production in Lake Washington for the fourth quarter of 2004 almost doubled as compared to the same period in 2003, averaging approximately 12,900 net barrels of oil equivalent per day in the fourth quarter of 2004, compared to approximately 6,900 net barrels of oil equivalent per day for the same period in 2003. During 2004, capital expenditures were also used for development in our other domestic core areas. New Zealand accounted for 16.3 Bcfe of production in 2004, a 16% decrease from production in the same period in 2003. Natural gas production in New Zealand declined primarily due to natural production declines in our TAWN properties. The TAWN gas contract was renegotiated to lower the total contract quantity and deliverability rates, and we anticipate meeting these revised contracted volumes. There is no penalty if the fields are unable to produce the minimum contracted volumes under the TAWN gas contract. New Zealand natural gas and natural gas liquids ("NGL") contracts are denominated in the New Zealand dollar, which has significantly strengthened during the last several years against the U.S. dollar.

Our production costs were up in 2004 predominantly because of increased production in Lake Washington, higher severance taxes due to increased domestic revenues, and currency exchange rates in New Zealand. Our general and administrative expenses increased in 2004 primarily due to an increase in costs related to our on going compliance efforts with the Sarbanes-Oxley Act, and to increased salaries and benefits.

Our debt to PV-10 ratio decreased to 18% at December 31, 2004 compared to 22% at December 31, 2003, due to higher crude oil and natural gas prices, which have increased our PV-10 value. Our debt to capitalization ratio was 43% at December 31, 2004 compared to 46% at year-end 2003, as debt levels increased slightly in 2004 but were offset by the increase in retained earnings as a result of current year profit. In June 2004, we repurchased $32.1 million of our 10-1/4% senior subordinated notes due 2009 through a tender offer. In July 2004, we repurchased $0.5 million of our 10-1/4% notes at the close of the tender offer. On August 1, 2004, we redeemed the remaining $92.5 million of these notes in accordance with our redemption rights under the indenture governing these notes. In 2004, we recorded approximately $9.5 million of debt retirement costs related to the repurchase of these notes. The redemption of these 10-1/4% notes lowered our effective interest rate.

Year-end 2004 proved reserves of 799.8 Bcfe, representing a 3% decline for the year, were 49% crude oil, 40% natural gas and 11% NGLs, compared to year-end 2003 proved reserves of 820.4 Bcfe, which were 47% crude oil, 41% natural gas and 12% NGLs. Proved developed reserves remained essentially the same at 56% of total reserves at year-end 2004, compared to 59% the previous year. Domestic proved reserves increased at year-end 2004 to 652.7 Bcfe, driven by the acquisition of reserves in December 2004 in the Bay de Chene and Cote Blanche Island fields, which were predominantly proved undeveloped. Proved reserves in New Zealand decreased to 147.1 Bcfe at year-end 2004, primarily attributable to 2004 production and slight downward revisions in the Manutahi and upper Tariki Sands. In 2004 we focused our drilling activity, both domestically and in New Zealand, on proved undeveloped locations that helped maximize production in a high-price environment, but which also resulted in smaller additions to proved reserves.

Results of Operations — Years Ended 2004, 2003, and 2002

Revenues. Our revenues in 2004 increased by 49% compared to revenues in 2003, and our revenues in 2003 increased by 39% compared to 2002 revenues due primarily to increases in oil and natural gas prices in each successive year and increases in production from our Lake Washington area. Revenues from our oil and gas sales comprised substantially all of total revenues for 2004 and 2003, and 94% of total revenues for 2002. Crude oil production comprised 49% of our production volumes in 2004, 38% in 2003, and 31% in 2002. Natural gas production comprised 41% of our production volumes in 2004, 53% in 2003, and 55% in 2002. Domestic production comprised 72% of our total production volumes in 2004, 64% in 2003, and 69% in 2002.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2004, 2003, and 2002:

Area	Oil and Gas Sales (In millions) 2004	2003	2002	Oil and Gas Sales Volume (Bcfe) 2004	2003	2002
AWP Olmos	$ 49.9	$ 43.7	$ 33.1	9.0	8.4	10.9
Brookeland	18.0	16.4	11.9	3.4	3.9	4.1
Lake Washington	152.3	59.5	18.5	23.2	12.1	4.4
Masters Creek	21.0	25.7	32.3	3.7	5.7	9.7
Other	17.5	18.9	16.3	2.8	3.7	5.2
Total Domestic	$ 258.7	$ 164.2	$ 112.1	42.1	33.8	34.3
Rimu/Kauri	24.5	11.6	4.0	5.3	3.3	1.5
TAWN	28.1	35.2	25.1	11.0	16.1	14.0
Total New Zealand	$ 52.6	$ 46.8	$ 29.1	16.3	19.4	15.5
Total	$ 311.3	$ 211.0	$ 141.2	58.3	53.2	49.8

Oil and gas sales in 2004 increased by 48%, or $100.3 million, from the level of those revenues for 2003, and our net sales volumes in 2004 increased by 10%, or 5.2 Bcfe, over net sales volumes in 2003. Average prices for oil increased to $40.24 per Bbl in 2004 from $29.89 per Bbl in 2003. Average natural gas prices increased to $4.12 per Mcf in 2004 from $3.42 per Mcf in 2003. Average NGL prices increased to $22.52 per Bbl in 2004 from $17.60 per Bbl in 2003.

In 2004, our $100.3 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $70.6 million favorable impact on sales, of which $48.9 million was attributable to the 35% increase in average oil prices received, $16.6 million was attributable to the 20% increase in natural gas prices and $5.1 million was attributable to the 28% increase in NGL prices; and
- Volume variances that had a $29.7 million favorable impact on sales, with $40.4 million of increases attributable to the 1.4 million Bbl increase in oil sales volumes and $3.8 million to the 217,000 Bbl increase in NGL sales volumes, offset by a decrease of $14.5 million due to the 4.3 Bcf decrease in natural gas sales volumes primarily from our TAWN area in New Zealand.

Oil and gas sales in 2003 increased by 49%, or $69.8 million, from the level of those revenues for 2002, and our net sales volumes in 2003 increased by 7%, or 3.4 Bcfe, over net sales volumes in 2002. Average prices for oil increased to $29.89 per Bbl in 2003 from $24.52 per Bbl in 2002. Average natural gas prices increased to $3.42 per Mcf in 2003 from $2.30 per Mcf in 2002. Average NGL prices increased to $17.60 per Bbl in 2003 from $12.82 per Bbl in 2002.

In 2003, our $69.8 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $59.0 million favorable impact on sales, of which $31.4 million was attributable to the 49% increase in average natural gas prices and $27.6 million was attributable to the 32% increase in average combined oil and NGL prices; and
- Volume variances that had a $10.8 million favorable impact on sales, with $8.8 million of the increases attributable to the 422,000 Bbl increase in oil and NGL sales volumes, and $2.0 million to the 0.9 Bcf increase in natural gas sales volumes.

The following table provides additional information regarding our quarterly oil and gas sales:

		Sales Volume: Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Average Sales Price: Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
2002:	First	594	351	6.6	12.3	$19.21	$10.83	$1.72
	Second	673	329	6.7	12.7	$25.11	$12.52	$2.60
	Third	683	225	6.7	12.2	$26.17	$13.58	$2.32
	Fourth	647	269	7.1	12.6	$27.00	$15.25	$2.55
	Total	2,597	1,174	27.1	49.8	$24.52	$12.82	$2.30
2003:	First	690	174	7.6	12.9	$32.73	$21.90	$3.71
	Second	822	211	7.1	13.3	$27.97	$15.81	$3.47
	Third	917	247	6.7	13.6	$29.24	$16.81	$3.17
	Fourth	941	191	6.6	13.4	$30.10	$16.71	$3.29
	Total	3,370	823	28.0	53.2	$29.89	$17.60	$3.42
2004:	First	1,124	277	5.9	14.3	$34.14	$22.30	$3.64
	Second	1,142	269	5.8	14.3	$37.24	$18.84	$4.19
	Third	1,076	251	6.0	13.9	$41.99	$23.33	$3.97
	Fourth	1,380	243	6.1	15.9	$46.33	$26.01	$4.67
	Total	4,722	1,040	23.7	58.3	$40.24	$22.52	$4.12

Costs and Expenses. Our expenses in 2004 increased $50.7 million, or 32%, compared to 2003 expenses. The majority of the increase was due to an $18.5 million increase in DD&A, an $11.4 million increase in severance and other taxes, and a $7.4 million increase in lease operating costs, all of which are primarily due to increased production volumes and oil and gas commodity prices in 2004. We also recorded $9.5 million of debt retirement costs in 2004. Our expenses in 2003 increased $26.6 million, or 20%, compared to 2002 expenses. The majority of the increase was due to a $4.9 million increase in lease operating costs, a $6.5 million increase in severance and other taxes, and a $6.8 million increase in DD&A, all of which increased as our production volumes and revenues increased in 2003.

Our 2004 general and administrative expenses, net, increased $3.7 million, or 26%, from the level of such expenses in 2003, while 2003 general and administrative expenses, net, increased $3.5 million, or 33%, over 2002 levels. The increase in both 2004 and 2003 were primarily due to compliance with the Sarbanes-Oxley Act, increased salaries and burdens, and our increased activities in New Zealand. In 2004, Sarbanes-Oxley Act compliance costs, including internal and external costs, totaled $2.2 million.. The increase in 2003 was also due to a reduction in reimbursements from partnerships that we managed as almost all of the partnerships have been liquidated, along with an increase in franchise tax expense. For the years 2004, 2003, and 2002, our capitalized general and administrative costs totaled $13.1 million, $11.5 million, and $10.7 million, respectively. Our net general and administrative expenses per Mcfe produced increased to $0.30 per Mcfe in 2004 from $0.27 per Mcfe in 2003 and $0.21 per Mcfe in 2002. The portion of supervision fees recorded as a reduction to general and administrative expenses was $5.8 million for 2004, $3.6 million for 2003, and $3.1 million for 2002.

DD&A increased $18.5 million, or 29%, in 2004 from 2003 levels, while 2003 DD&A increased $6.8 million, or 12%, from 2002 levels. Domestically, DD&A increased $17.6 million in 2004 due to increases in the depletable oil and gas property base, higher production in the 2004 period and slightly lower reserve volumes. In New Zealand, DD&A increased by $0.9 million in 2004 due to increases in the depletable oil and gas property base along with lower reserve volumes, offset by lower production in the 2004 period. In 2003, our domestic DD&A increased by $1.0 million due to increases in the depletable oil and gas property base, offset by slightly lower production in the 2003 period and higher reserve volumes that were added primarily through our Lake Washington activities. Our New Zealand DD&A increased by $5.8 million in 2003 due to increased production in the 2003 period. Our DD&A rate per Mcfe of production was $1.40 in 2004, $1.19 in 2003, and $1.13 in 2002, resulting from increases in per unit cost of reserves additions.

We recorded $0.7 million and $0.9 million of accretions to our asset retirement obligation in 2004 and 2003, respectively.

Our lease operating costs per Mcfe produced were $0.71 in 2004, $0.64 in 2003 and $0.58 in 2002. There were no supervision fees recorded as a reduction to production costs in 2004, while there were $1.5 million in 2003 and $2.1 million in 2002. Our lease operating costs in 2004 increased $7.4 million, or 22%, over the level of such expenses in 2003, while 2003 costs increased $4.9 million, or 17% over 2002. Approximately $6.2 million of the increase in lease operating costs during 2004 was related to our domestic operations, which increased primarily due to increased compression and chemical costs in Lake Washington resulting from higher production from our Lake Washington area along with the reduction of 2003 expense of $1.5 million from supervision fees. Our lease operating cost in New Zealand increased in 2004 by $1.2 million due to the continued development of our Rimu/Kauri area and the increased currency exchange rate of the New Zealand dollar as compared to the U.S. dollar. Approximately $4.2 million of the increase in 2003 was due to our New Zealand operations as production increased over 2002 levels.

Severance and other taxes increased $11.4 million, or 60% over 2003 levels, while in 2003 these taxes increased $6.5 million, or 51% over 2002 levels. The increase was due primarily to higher commodity prices and increased Lake Washington and Rimu/Kauri production in each of the periods. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.8%, 9.0% and 8.9% in 2004, 2003 and 2002, respectively.

Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $6.2 million in 2004. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled $19.2 million in 2004, $19.1 million in 2003 and $13.5 million in 2002. Interest expense on our 10-1/4% senior subordinated notes issued in August 1999 and repurchased and retired in 2004, including amortization of debt issuance costs, totaled $7.4 million in 2004, and $13.2 million in both 2003 and 2002. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2004, $1.6 million in 2003, and $3.6 million in 2002. Other interest cost was $0.3 million in 2003. Our total interest cost in 2004 was $34.2 million, of which $6.5 million was capitalized. Our total interest cost in 2003 was $34.2 million, of which $6.8 million was capitalized. Our total interest cost in 2002 was $30.3 million, of which $7.0 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in 2004 was due to lower capitalized interest than in 2003. The increase in interest expense in 2003 was attributed to the replacement of our bank borrowings in April 2002 with our 9-3/8% senior subordinated notes due 2012 with a longer repayment term but a higher interest rate.

In 2004, we incurred $9.5 million of debt retirement costs related to the repurchase and redemption of our 10-1/4% senior subordinated notes due 2009. The costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount and approximately $0.2 million of other costs.

The overall effective tax rate was 32.5% in both 2004 and 2003 and 35.2% in 2002. The effective tax rate for 2004 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation, along with favorable corrections to tax basis amounts discovered while preparing the prior year's tax returns. These amounts were partially offset by higher deferred state income taxes. Income tax expense in 2003 includes a reduction of approximately $1.3 million from the U.S. statutory rate, primarily from the result of the currency exchange rate effect on the New Zealand deferred tax. This amount was partially offset by higher domestic state income taxes and other items.

As discussed in Note 1 to the consolidated financial statements, we adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million, which was recorded as a cumulative effect of change in accounting principle in the 2003 consolidated statement of income.

Net Income. Our net income in 2004 of $68.5 million was 129% higher than our 2003 net income of $29.9 million due to higher commodity prices and increased production.

Our net income in 2003 of $29.9 million was 151% higher than our 2002 net income of $11.9 million due to higher commodity prices and increased production.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2004 are as follows:

	2005	2006	2007	2008	2009	Thereafter	Total
				(In thousands)			
Non-cancelable operating leases[1]	$ 2,476	$ 2,559	$ 2,519	$ 2,472	$ 2,342	$ 13,025	$ 25,393
Asset retirement obligation[2]	463	515	515	515	515	15,116	17,639
Drilling rigs and seismic	4,355	—	—	—	—	—	4,355
7-5/8% senior notes due 2011[3]	—	—	—	—	—	150,000	150,000
9-3/8% senior subordinated notes due 2012[3]	—	—	—	—	—	200,000	200,000
Credit facility[4]	—	—	—	7,500	—	—	7,500
Total	$ 7,294	$ 3,074	$ 3,034	$ 10,487	$ 2,857	$ 378,141	$ 404,887

[1]Our office lease in Houston, Texas, extends until 2015.
[2]Amounts shown by year are the fair values at December 31, 2004.
[3]Amounts do not include the interest obligation, which is paid semiannually.
[4]The credit facility expires in October 2008, and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is currently significantly higher when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by OPEC, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas. Such factors are beyond our control.

Liquidity and Capital Resources

During 2004, we largely relied upon our net cash provided by operating activities of $182.6 million, the issuance of our 7-5/8% senior notes due 2011, proceeds from the sale of non-core properties and equipment of $5.1 million, less the repayment of our 10-1/4% senior subordinated notes due 2009 to fund capital expenditures of $171.1 million and acquisitions of $27.2 million. During 2003, we relied upon our net cash provided by operating activities of $110.8 million, proceeds from bank borrowings of $15.9 million, and proceeds from the sale of non-core properties and equipment of $10.2 million to fund capital expenditures of $144.5 million.

Net Cash Provided by Operating Activities. For 2004, our net cash provided by operating activities was $182.6 million, representing a 65% increase as compared to $110.8 million generated during 2003. The $71.8 million increase in 2004 was primarily due to an increase of $100.3 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher domestic production and severance taxes as a result of higher commodity prices in 2004. In 2003, net cash provided by operating activities increased by 55% to $110.8 million, as compared to $71.6 million in 2002. The 2003 increase of $39.2 million was primarily due to an increase of oil and gas sales of $69.8 million due to higher commodity prices and production.

Accounts Receivable. Included in the "Accounts receivable" balance, which totaled $39.0 million and $27.4 million at December 31, 2004 and 2003, respectively, on the accompanying balance sheets, is approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2002 and 2001 that have been disputed since early 2003. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003.

We assess the collectibility of accounts receivable and, based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2004 and 2003, we had an allowance for doubtful accounts of $0.5 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying consolidated balance sheets.

Sarbanes-Oxley Compliance Costs. We have incurred substantial costs to comply with the Sarbanes-Oxley Act of 2002. These expenditures have reduced our net cash provided by operating activities in each of the last two years. In 2004, Sarbanes-Oxley Act compliance costs, including internal and external costs, totaled $2.2

million and are reflected in "General and administrative, net" on the accompanying statements of income. We expect the costs of Sarbanes-Oxley compliance to decrease from 2004 levels in future years.

Existing Credit Facility. We had $7.5 million in borrowings under our bank credit facility at December 31, 2004, and $15.9 million in outstanding borrowings at December 31, 2003. Our bank credit facility at December 31, 2004 consisted of a $400.0 million revolving line of credit with a $250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at $250.0 million, effective November 1, 2004. In June 2004, we renewed this credit facility, increasing the facility amount to $400.0 million from $300.0 million and extending its expiration to October 1, 2008 from October 1, 2005. We maintained the commitment amount at $150.0 million, which amount was set at our request effective May 9, 2003. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. Our revolving credit facility includes, among other restrictions that changed somewhat as the facility was renewed and extended, requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any "material adverse condition" clause, a clause that is common for credit agreements to include. A "material adverse condition" clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on our operations, financial condition, prospects or properties, and would impair our ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Working Capital. Our working capital improved from a deficit of $35.9 million at December 31, 2003, to a deficit of $14.2 million at December 31, 2004. The improvement primarily resulted from a decrease in accrued capital costs due to a reduction in our drilling activities at year-end 2004 in comparison with year-end 2003 activity, along with an increase in accounts receivable for oil and gas sales due to higher sales volumes and commodity prices.

Repurchase of 10-1/4% Senior Subordinated Notes Due 2009. In June 2004, we repurchased $32.1 million of our 10-1/4 senior subordinated notes due 2009 pursuant to a tender offer, and recorded debt retirement costs of $2.7 million related to this repurchase. In July 2004, we repurchased approximately $0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining $92.5 million of these notes. We have recorded a total of $9.5 million in debt retirement costs related to the total repurchase of these notes.

Debt Maturities. Our credit facility extends until October 1, 2008. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

Capital Expenditures. We relied upon our net cash provided by operating activities of $182.6 million, the issuance of our 7-5/8% senior notes due 2011, and proceeds from the sale of non-core properties and equipment of $5.1 million, less the repayment of our 10-1/4% senior subordinated notes due 2009, to fund capital expenditures of $171.1 million and acquisitions of $27.2 million. Our total capital expenditures of approximately $198.3 million in 2004 included:

Domestic expenditures of $162.5 million as follows:

- $87.7 million for drilling and developmental activity costs, predominantly in our Lake Washington area;
- $31.8 million on property acquisitions, including $27.2 million to acquire properties in the Bay de Chene and Cote Blanche Island fields;
- $28.7 million of domestic prospect costs, principally prospect leasehold, Lake Washington three-dimensional seismic activity, and geological costs of unproved prospects;
- $9.9 million on exploratory drilling, mainly in our Lake Washington area;
- $2.5 million primarily for a field office building, computer equipment, software, furniture, and fixtures;
- $1.3 million on field compression facilities; and
- $0.6 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand expenditures of $35.8 million as follows:

- $26.7 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $7.0 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $1.2 million on gas processing plants;
- $0.7 million on exploratory drilling; and
- $0.2 million for computer equipment, software, furniture, and fixtures.

We have spent considerable time and capital in 2004 and 2003 on significant facility capacity upgrades in the Lake Washington field to increase facility capacity to approximately 20,000 barrels per day for crude oil, up from 9,000 barrels per day capacity in the first quarter of 2003. We have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility.

We successfully completed 51 of 66 wells in 2004, for a success rate of 77%. Domestically, we completed 37 of 44 development wells for a success rate of 84% and completed four of ten exploration wells. A total of 30 wells were drilled in the Lake Washington area, of which 21 were completed, and 15 wells were drilled in the AWP Olmos area, of which 13 were completed. In New Zealand, we completed 10 of 12 wells, consisting of four Kauri sand wells drilled, five of six Manutahi sand wells, and the Tariki-D1 well.

Our 2005 capital expenditure budget is $200 million to $220 million, net of $5 million to $15 million of dispositions and excluding any acquisitions. Approximately 80% of the budget is targeted for domestic activities, primarily in South Louisiana, with about 20% planned for activities in New Zealand. Approximately $15 million to $20 million of the 2005 budget will be focused on activity in the newly acquired properties in Bay de Chene and Cote Blanche

Island fields. The $5 million to $15 million of dispositions relate to non-core properties planned for later in 2005. We expect that our 2005 capital expenditures will begin at the low end of the range, and depending on commodity prices and operational performance, they may increase to the high end of the range during the course of the year. We anticipate 2005 capital expenditures to approximate our cash flows provided from operating activities during 2005, similar to 2004. For 2005, we are targeting total production and proved reserves to increase 7% to 12% over the 2004 levels.

Our capital expenditures were approximately $144.5 million in 2003 and $155.2 million in 2002. During 2003, we relied upon our net cash provided by operating activities of $110.8 million, proceeds from bank borrowings of $15.9 million, and proceeds from the sale of non-core properties and equipment of $10.2 million to fund capital expenditures of $144.5 million. During 2002, we principally relied upon cash provided by operating activities of $71.6 million, net proceeds from the issuance of long-term debt of $195.0 million of 9-3/8% senior subordinated notes due 2012, and net proceeds from our public stock offering of $30.5 million, less the repayment of bank borrowings of $134.0 million, to fund capital expenditures of $155.2 million. Our capital expenditures in 2003 of approximately $144.5 million included:

Domestic activities of $114.4 million as follows:

- $57.0 million on drilling and developmental activities, primarily in our Lake Washington area;
- $25.9 million for the construction of production and surface facilities, mainly in our Lake Washington area;
- $11.9 million on exploratory drilling, primarily in our Lake Washington area;
- $11.4 million on domestic prospect costs, principally leasehold, seismic, and geological costs;
- $4.4 million on field compression facilities;
- $2.0 million for producing property acquisitions;
- $0.9 million for fixed assets; and
- $0.9 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand activities of $30.1 million as follows:

- $15.1 million on developmental activities primarily to further delineate the Rimu/Kauri area;
- $6.4 million on prospect costs;
- $5.7 million on gas processing plants;
- $2.3 million for exploratory drilling mainly for the Tuihu exploratory well;
- $0.3 million on producing properties acquisitions; and
- $0.3 million for fixed assets.

In 2003, we participated in drilling 63 domestic development wells and eight domestic exploratory wells, of which 53 development wells and five exploratory wells were completed. In New Zealand we drilled and completed three development wells and drilled one unsuccessful exploratory well.

Income Tax Regulations

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. We do not believe the recently enacted American Jobs Creation Act of 2004 will have a material impact on our financial position or cash flow from operations in the near-term.

New Accounting Principles

In January 2003, the FASB issued Interpretation No. 46 (Revised December 2003) ("FIN 46R"), Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 consolidated financial statements (the "Interpretation"). The Interpretation significantly changes whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model—the variable interest model; which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. The Interpretation provides guidance for determining whether an entity lacks sufficient equity or its equity holders lack adequate decision-making ability. These variable interest entities ("VIEs") are covered by the Interpretation and are to be evaluated for consolidation based on their variable interests. These provisions applied immediately to variable interests in VIEs created after January 31, 2003, and to variable interests in special purpose entities for periods ending after December 15, 2003. The provisions apply for all other types of variable interests in VIEs for periods ending after March 15, 2004. We have no variable interests in VIEs, nor do we have variable interests in special purpose entities. The adoption of this interpretation had no impact on our financial position or results of operations.

In September and November 2004, the EITF discussed a proposed framework for addressing when a limited partnership should be consolidated by its general partner, EITF Issue 04-5. The proposed framework presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or protective rights would be considered substantive and preclude consolidation by the general partner and what limited partner's rights would be considered participating rights that would preclude consolidation by the general partner. The EITF tentatively concluded that for kick out rights to be considered substantive, the conditions specified in paragraph B20 of FIN 46R should be met. With regard to the definition of participating rights that would preclude consolidation by the general partner, the EITF concluded that the definition of those rights should be consistent with those in EITF Issue 96-16. The EITF also reached a tentative conclusion on the transition for Issue 04-05. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106 (SAB 106). SAB 106 expresses the SEC staff's views regarding SFAS No. 143 and its impact on both the full-cost ceiling test and the calculation of depletion expense. In accordance with SAB 106, beginning in the fourth quarter of 2004, undiscounted abandonment cost for future wells, not recorded at the present time but needed to develop the proved reserves in existence at the present time, should be included in the unamortized cost of oil and gas properties, net of related salvage value, for purposes of computing DD&A. The effect of including undiscounted abandonment costs of future wells to the undiscounted cost of oil and gas properties will increase depletion expense in future periods, however, we currently do not believe such increases will be material.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.
- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

We have elected to adopt the provisions of SFAS No. 123R on July 1, 2005 using the modified prospective method. As permitted by Statement 123, the Company currently accounts for share-based payments to employees using APB Opinion No. 25's intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R's fair value method is expected to have a significant impact on our result of operations. However, it will have no impact on our overall financial position. We currently use the Black-Scholes formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model upon the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share in "Stock Based Compensation," under Note 1 to our accompanying consolidated financial statements. Statement No. 123R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption. While the Company cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of excess tax deductions recognized were $2.0 million, $0.2 million, and $0.3 million in 2004, 2003 and 2002, respectively. These deductions resulted in an increase in operating cash flows, however, due to the Company's net operating tax loss position, deferred income taxes were reduced rather than actual cash taxes paid.

Proved Oil and Gas Reserves

At year-end 2004, our total proved reserves were 799.8 Bcfe with a PV-10 Value of $2.0 billion. In 2004, our proved natural gas reserves decreased 17.6 Bcf, or 5%, while our proved oil reserves increased 1.8 MMBbl, or 3%, and our NGL reserves decreased 2.3 MMBbl, or 14%, for a total equivalent decrease of 20.5 Bcfe, or 3%. In 2003, our proved natural gas reserves increased by 9.1 Bcf, or 3%, while our proved oil reserves increased by 11.4 MMBbl, or 22%, and our NGL reserves decreased by 1.0 MMBbl, or 6%, for a total equivalent increase of 71.0 Bcfe, or 9%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 7.2 Bcfe (all of which was domestic) of proved reserves in 2004, 105.6 Bcfe (36.1 Bcfe of which came from New Zealand) in 2003, and 83.9 Bcfe (15.9 Bcfe of which came from New Zealand) in 2002. Through acquisitions we added 43.4 Bcfe of proved reserves in 2004, 0.5 Bcfe in 2003, and 74.2 Bcfe in 2002. At year-end 2004, 56% of our total proved reserves were proved developed, compared with 59% at year-end 2003 and 60% at year-end 2002.

The PV-10 Value of our total proved reserves increased 31% from the PV-10 Value at year-end 2003. Gas prices increased in 2004 to $5.16 per Mcf from $4.56 per Mcf at year-end 2003, compared to $3.49 per Mcf at year-end 2002. Oil prices increased in 2004 to $41.07 per Bbl from $30.16 per Bbl at year-end 2003, compared to $29.27 in 2002. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant, for that year's reserve calculation, throughout the life of the properties. Subsequent changes to such year-end oil and gas prices could have a significant impact on the calculated PV-10 Value.

Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates that were used to prepare these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of our properties and the related present value of estimated future net cash flows from these properties,

- accruals related to oil and gas production and revenues, capital expenditures and lease operating and severance tax expenses,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any significant revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2004, 2003, and 2002, such internal costs capitalized totaled $13.1 million, $11.5 million, and $10.7 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2004, 2003, and 2002, capitalized interest on unproved properties totaled $6.5 million, $6.8 million, and $7.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from asset retirement obligations, including future abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). Our hedges at year-end 2004 consisted mainly of natural gas and crude oil price floors with strike prices lower than the period end price and thus did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis for those countries with proved reserves.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2004, 2003 and 2002, we recognized net losses of $1.3 million, $2.8 million and $0.2 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2004, the Company had recorded $0.5 million, net of taxes of $0.3 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2004, 2003 and 2002 was not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next twelve months when the forecasted sale of hedged production occurs.

At December 31, 2004, we had in place price floors in effect through the December 2004 contract month for natural gas, these cover a portion of our domestic natural gas production for January 2005 to December 2005. The natural gas price floors cover notional volumes of 4,000,000 MMBtu, with a weighted average floor price of $5.83 per MMBtu. Our natural gas price floors in place at December 31, 2004 are expected to cover approximately 30% to 35% of our domestic natural gas production from January 2005 to December 2005. At December 31, 2004, we also had in place crude oil price floors in effect through the March 2005 contract month, which cover a portion our domestic crude oil production for January 2005 to March 2005. The crude oil price floors cover notional volumes of 216,000 barrels, with a weighted average floor price of $37.00 per barrel. Our crude oil price floors in place at December 31, 2004 are expected to cover approximately

15% to 20% of our domestic crude oil production from January 2005 to March 2005.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas and crude oil production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the consolidated statement of income. The fair value of our derivatives are computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2004, was $1.8 million and is recognized on the balance sheet in "Other current assets."

From January 2005 to the date of this filing, we entered into additional natural gas price floors covering contract periods April 2005 to October 2005, which cover our natural gas production for April 2005 to October 2005. Notional volumes are 1,300,000 MMBtu at a weighted average floor price of $5.73 per MMBtu.

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of commodity risk.

Stock Based Compensation. We have two stock-based compensation plans, which are described more fully in Note 6 to our accompanying consolidated financial statements. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. We issued restricted stock for the first time in 2004, and recorded expense related to these shares of less than $0.1 million in "General and administrative, net" on the accompanying statements of income. No stock-based employee compensation cost is reflected in net income for employee stock options, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities' cash flows, commodity pricing, environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, predominantly a portion of our "Deferred income taxes" and a portion of our "Asset Retirement Obligation" on the accompanying balance sheet. For accounts other than "Deferred income taxes," as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Price-risk management and other, net" on the accompanying statements of income. We recognize transaction gains and losses on "Deferred income taxes" in "Provision for Income Taxes" on the accompanying statement of income.

Related-Party Transactions

We have been the operator of a number of properties owned by affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships totaled approximately $0.2 million in 2004 and 2003 and approximately $0.3 million in 2002 and are recorded as reductions of general and administrative, net. We also have been reimbursed for administrative and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $0.2 million, $0.4 million, and $1.0 million in 2004, 2003, and 2002, respectively, and are recorded as reductions in general and administrative, net. Included in "Accounts receivable" and "Accounts payable and accrued liabilities" on the accompanying balance sheets is less than $0.1 million and $1.1 million, respectively, in receivables from and payables to the partnerships at December 31, 2004.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled by the sister of the Company's Chairman and Vice Chairman of the Board. The sister and brother-in-law of Messrs. A. E. Swift and V. Swift also own a substantial majority of Tec-Com. In 2004, 2003 and 2002, we paid approximately $0.4 million per year to Tec-Com for such services pursuant to the terms of the contract between the parties. The contract was renewed June 30, 2004 on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services. As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee's charter.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "future," "estimate," "expect," "budget," "predict," "anticipate," "projected," "should," "believe," or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices, internationally or in the United States; availability of services and supplies; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for capital; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- *Price Floors* – At December 31, 2004, we had in place price floors in effect through the December 2005 contract month for natural gas, these cover a portion of our domestic natural gas production for January 2005 to December 2005. The natural gas price floors cover notional volumes of 4,000,000 MMBtu, with a weighted average floor price of $5.83 per MMBtu. Our natural gas price floors in place at December 31, 2004 are expected to cover approximately 30% to 35% of our domestic natural gas production from January 2005 to December 2005. At December 31, 2004, we also had in place crude oil price floors in effect through the March 2005 contract month, which cover a portion of our domestic crude oil production for January 2005 to March 2005. The crude oil price floors cover notional volumes of 216,000 barrels, with a weighted average floor price of $37.00 per barrel. Our crude oil price floors in place at December 31, 2004 are expected to cover approximately 15% to 20% of our domestic crude oil production from January 2005 to March 2005. The fair value of these instruments at December 31, 2004, was $1.8 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be sustained from these price floors in 2005 would be their fair value at December 31, 2004 of $1.8 million.
- *New Zealand Gas Contracts* – All of our gas production in New Zealand is sold under long-term, fixed-price contracts denominated in New Zealand Dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2003, we had $7.5 million in outstanding borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 53 basis points and would reduce 2005 cash flows by less than $0.1 million based on the December 31, 2004 level of borrowing.

Income Tax Carryforwards. We had significant federal and state net operating loss and capital loss carryforwards at December 31, 2004. The Company has not recorded a valuation allowance against the deferred tax assets attributable to these carryovers at December 31, 2004, as management estimates that it is more likely than not that these assets will be fully utilized before they expire except for a $0.5 million valuation allowance against the capital loss carryforward, as detailed in Note 3 of the accompanying consolidated financial statements. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts. If we are not able to use our carryforwards, our results of operations and cash flows will be negatively impacted.

Financial Instruments and Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2004 and 2003, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2004 and 2003, the fair values of our senior subordinated notes due 2012 were $224.0 million, or 112.0% of face value, and $218.0 million, or 109% of face value, respectively. Based upon quoted market prices as of December 31, 2004, the fair value of our senior notes due 2011 was $162.4 million, or 108.25% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2004 and 2003. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2004.

Foreign Currency Risk. We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand Dollar. Fluctuations in rates between the New Zealand Dollar and U.S. Dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand Dollars. We use the U.S. Dollar as our functional currency in New Zealand and because of this, our results of operations, cash flows and effective tax rate are impacted from fluctuations between the U.S. Dollar and the New Zealand Dollar.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe the loss of any single oil or gas customer would have a material adverse effect on our results of operations.

Management's Report on Internal Control Over Financial Reporting

Management of Swift Energy Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Management of the Company assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2004.

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.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management's assessment of the Company's internal control over financial reporting as of December 31, 2004. That report, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, appears on the following page.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of Swift Energy Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Swift Energy Company 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 (the COSO criteria). Swift Energy Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, management's assessment that Swift Energy Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Swift Energy Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Swift Energy Company as of December 31, 2004 and 2003, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2004 and our report dated March 11, 2005 expressed an unqualified opinion thereon.

Ernst + Young LLP

ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Swift Energy Company's 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 and our report dated March 11, 2005 expressed an unqualified opinion thereon.

Ernst + Young LLP

ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

	December 31, 2004	December 31, 2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,920,118	$ 1,066,280
Accounts receivable—		
Oil and gas sales	38,029,409	26,082,650
Joint interest owners	1,013,938	1,350,707
Other current assets	10,422,531	4,961,320
Total Current Assets	54,385,996	33,460,957
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,479,681,903	1,305,110,582
Unproved properties	80,121,509	67,557,969
	1,559,803,412	1,372,668,551
Furniture, fixtures, and other equipment	12,820,622	10,602,786
	1,572,624,034	1,383,271,337
Less — Accumulated depreciation, depletion, and amortization	(649,185,874)	(567,464,334)
	923,438,160	815,807,003
Other Assets:		
Deferred income taxes	1,666,058	1,905,909
Debt issuance costs	9,148,977	8,015,575
Restricted assets	1,933,956	649,100
	12,748,991	10,570,584
	$ 990,573,147	$ 859,838,544
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 29,406,877	$ 26,247,477
Accrued capital costs	22,489,467	29,417,542
Accrued interest	9,209,192	8,748,656
Undistributed oil and gas revenues	7,512,755	4,939,667
Total Current Liabilities	68,618,291	69,353,342
Long-Term Debt	357,500,000	340,254,783
Deferred Income Taxes	73,106,580	43,498,682
Asset Retirement Obligation	17,176,136	9,340,473
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 85,000,000 shares authorized, 28,570,632 and 28,011,109 shares issued, and 28,089,764 and 27,484,091 shares outstanding, respectively	285,706	280,111
Additional paid-in capital	343,536,298	334,865,204
Treasury stock held, at cost, 480,868 and 527,018 shares, respectively	(6,896,245)	(7,558,093)
Unearned compensation	(1,728,585)	—
Retained earnings	138,524,301	70,073,384
Accumulated other comprehensive income (loss), net of income tax	450,665	(269,342)
	474,172,140	397,391,264
	$ 990,573,147	$ 859,838,544

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2004	2003	2002
Revenues:			
Oil and gas sales	$311,285,172	$211,032,639	$141,195,713
Gain on asset disposition	—	—	7,332,668
Price-risk management and other, net	(1,008,398)	(2,131,656)	1,441,430
	310,276,774	208,900,983	149,969,811
Costs and Expenses:			
General and administrative, net	17,787,125	14,097,066	10,564,849
Depreciation, depletion, and amortization	81,580,828	63,072,057	56,224,392
Accretion of asset retirement obligation	673,654	857,356	—
Lease operating cost	41,214,256	33,833,198	28,918,858
Severance and other taxes	30,401,293	19,033,604	12,578,454
Interest expense, net	27,643,108	27,268,524	23,274,969
Debt retirement cost	9,536,268	—	—
	208,836,532	158,161,805	131,561,522
Income Before Income Taxes and Change in Accounting Principle	101,440,242	50,739,178	18,408,289
Provision for Income Taxes	32,989,325	16,468,514	6,485,062
Income Before Change in Accounting Principle	$ 68,450,917	$ 34,270,664	$ 11,923,227
Cumulative Effect of Change in Accounting Principle (net of taxes)	—	4,376,852	—
Net Income	$ 68,450,917	$ 29,893,812	$ 11,923,227
Per Share Amounts—			
Basic: Income Before Change in Accounting Principle	$ 2.46	$ 1.25	$ 0.45
Change in Accounting Principle	—	(0.16)	—
Net Income	$ 2.46	$ 1.09	$ 0.45
Diluted: Income Before Change in Accounting Principle	$ 2.41	$ 1.24	$ 0.45
Change in Accounting Principle	—	(0.16)	—
Net Income	$ 2.41	$ 1.08	$ 0.45
Weighted Average Shares Outstanding	27,822,413	27,357,579	26,382,906

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity

Swift Energy Company and Subsidiaries

	Common Stock[1]	Additional Paid-in Capital	Treasury Stock	Unearned Compen-sation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2001	$256,346	$ 296,172,820	$ (12,032,791)	$ —	$ 28,256,345	$ —	$ 312,652,720
Stock issued for benefit plans (38,149 shares)	292	617,960	127,795	—	—	—	746,047
Stock options exercised (112,995 shares)	1,130	924,719	—	—	—	—	925,849
Tax benefits from exercise of stock options	—	281,694	—	—	—	—	281,694
Public stock offering (1,725,000 shares)	17,250	30,465,809	—	—	—	—	30,483,059
Employee stock purchase plan (9,801 shares)	98	122,343	—	—	—	—	122,441
Stock issued in acquisitions (520,000 shares)	3,000	4,958,126	3,155,074	—	—	—	8,116,200
Comprehensive income:							
Net income	—	—	—	—	11,923,227	—	11,923,227
Change in fair value of cash flow hedges, net of income tax	—	—	—	—	—	(178,053)	(178,053)
Total comprehensive income	—	—	—	—	—	—	11,745,174
Balance, December 31, 2002	$278,116	$ 333,543,471	$ (8,749,922)	$ —	$ 40,179,572	$(178,053)	$ 365,073,184
Stock issued for benefit plans (83,201 shares)	1	(408,178)	1,191,829	—	—	—	783,652
Stock options exercised (142,807 shares)	1,428	1,158,984	—	—	—	—	1,160,412
Tax benefits from exercise of stock options	—	156,980	—	—	—	—	156,980
Employee stock purchase plan (56,574 shares)	566	413,947	—	—	—	—	414,513
Comprehensive income:							
Net income	—	—	—	—	29,893,812	—	29,893,812
Change in fair value of cash flow hedges, net of income tax	—	—	—	—	—	(91,289)	(91,289)
Total comprehensive income	—	—	—	—	—	—	29,802,523
Balance, December 31, 2003	$280,111	$ 334,865,204	$ (7,558,093)	$ —	$ 70,073,384	$(269,342)	$ 397,391,264
Stock issued for benefit plans (46,150 shares)	—	166,298	661,848	—	—	—	828,146
Stock options exercised (509,105 shares)	5,091	4,260,882	—	—	—	—	4,265,973
Tax benefits from exercise of stock options	—	1,956,555	—	—	—	—	1,956,555
Employee stock purchase plan (50,418 shares)	504	502,097	—	—	—	—	502,601
Issuance of restricted stock	—	1,785,262	—	(1,785,262)	—	—	—
Amortization of restricted stock compensation	—	—	—	56,677	—	—	56,677
Comprehensive income:							
Net income	—	—	—	—	68,450,917	—	68,450,917
Change in fair value of cash flow hedges, net of income tax	—	—	—	—	—	720,007	720,007
Total comprehensive income	—	—	—	—	—	—	69,170,924
Balance, December 31, 2004	$285,706	$ 343,536,298	$ (6,896,245)	$(1,728,585)	$ 138,524,301	$ 450,665	$ 474,172,140

[1] $.01 par value.

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2004	2003	2002
Cash Flows from Operating Activities:			
Net income	$ 68,450,917	$ 29,893,812	$ 11,923,227
Adjustments to reconcile net income to net cash provided by operating activities—			
Cumulative effect of change in accounting principle	—	4,376,852	—
Depreciation, depletion, and amortization	81,580,828	63,072,057	56,224,392
Accretion of asset retirement obligation	673,654	857,356	—
Deferred income taxes	32,513,325	16,332,492	6,482,724
Debt retirement cost – cash and non-cash	9,536,268	—	—
Gain on asset disposition	—	—	(7,332,668)
Other	(435,439)	908,927	270,770
Change in assets and liabilities—			
(Increase) decrease in accounts receivable	(11,040,543)	(7,163,304)	883,419
Increase in accounts payable and accrued liabilities	843,341	2,432,111	206,163
Increase in accrued interest	460,536	116,976	2,968,287
Net Cash Provided by Operating Activities	182,582,887	110,827,279	71,626,314
Cash Flows from Investing Activities:			
Additions to property and equipment	(171,095,101)	(144,503,180)	(103,773,337)
Proceeds from the sale of property and equipment	5,058,147	10,186,970	13,256,674
Acquisition of TAWN fields	—	—	(51,460,586)
Acquisition of Bay de Chene and Cote Blanche Island fields	(27,196,336)	—	—
Net cash received as operator of oil and gas properties	3,921,673	3,073,718	4,152,645
Net cash received (distributed) as operator of partnerships	884,093	260,726	(23,241,501)
Other	(658,630)	(71,193)	(39,953)
Net Cash Used in Investing Activities	(189,086,154)	(131,052,959)	(161,106,058)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	150,000,000	—	200,000,000
Payments of long-term debt	(125,000,000)	—	—
Net proceeds from (payments of) bank borrowings	(8,400,000)	15,900,000	(134,000,000)
Net proceeds from issuances of common stock	4,825,251	1,575,853	31,409,200
Payments of debt retirement costs	(6,734,611)	—	—
Payments of debt issuance costs	(4,333,535)	—	(6,262,435)
Net Cash Provided by Financing Activities	10,357,105	17,475,853	91,146,765
Net Increase (Decrease) in Cash and Cash Equivalents	$ 3,853,838	$ (2,749,827)	$ 1,667,021
Cash and Cash Equivalents at Beginning of Year	1,066,280	3,816,107	2,149,086
Cash and Cash Equivalents at End of Year	$ 4,920,118	$ 1,066,280	$ 3,816,107
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 26,064,158	$ 25,763,169	$ 19,189,822
Cash paid during year for income taxes	$ 476,000	$ 129,738	$ 2,500
Non-Cash Financing Activity:			
Issuance of common stock in acquisitions	$ —	$ —	$ 8,116,200

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy Company and our wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New Zealand. Our investments in oil and gas limited partnerships where we are the general partner, and our undivided interests in gas processing plants, are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2004, 2003, and 2002, such internal costs capitalized totaled $13.1 million, $11.5 million, and $10.7 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2004, 2003, and 2002, capitalized interest on unproved properties totaled $6.5 million, $6.8 million, and $7.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependant on our production from these properties in future years. Our total amortization per Mcfe was $1.38, $1.17, and $1.11 in 2004, 2003, and 2002, respectively. Our domestic amortization per Mcfe was $1.46, $1.30, and $1.25 in 2004, 2003, and 2002, respectively. Our New Zealand amortization per Mcfe was $1.17, $0.94, and $0.80 in 2004, 2003 and 2002, respectively. Furniture, fixtures, and other equipment, held at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (G&G) costs incurred on developed properties are recorded in Proved Property and therefore subject to amortization. In exploration areas, G&G costs directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect.

The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). Our hedges at year-end 2004 consisted mainly of natural gas and crude oil price floors with strike prices lower than the period end price and thus did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2004, we did not have any material natural gas imbalances.

Accounts Receivable. Included in the "Accounts receivable" balance, which totaled $39.0 million and $27.4 million at December 31, 2004 and 2003, respectively, on the accompanying balance sheets, is approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that have been disputed since early 2003. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003.

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2004 and 2003, we had an allowance for doubtful accounts of $0.5 million. These allowances for doubtful accounts have been deducted from the total "Accounts receivable" balances on the accompanying consolidated balance sheets.

Debt Issuance Costs. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in April 2002 of our 9-3/8% senior subordinated notes due 2012, the June 2004 extension of our bank credit facility, and the public offering in June 2004 of our 7-5/8% senior notes due 2011 were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility. The 9-3/8% senior subordinated notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2004, was $4.6 million, net of accumulated amortization of $1.0 million. The issuance costs associated with our revolving credit facility, which was extended in June 2004, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2004, was $0.8 million, net of accumulated amortization of $1.6 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2004, was $3.7 million, net of accumulated amortization of $0.2 million. The remaining $2.2 million of debt issuance costs related to the 10-1/4% senior subordinated notes due 2009 was charged to "debt retirement cost" on the accompanying statements of income when the related debt was retired in 2004.

Limited Partnerships. At year-end 2004, we serve as managing general partner for six private limited partnerships, and during fiscal 2004, less than 1% of our total oil and gas sales was attributable to our interests in those partnerships. These six partnerships were formed between 1996 and 1998, and will continue to operate until their limited partners vote otherwise.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2004, 2003 and 2002, we recognized net losses of $1.3 million, $2.8 million and $0.2 million, respectively, relating to our derivative activities.

This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2004, the Company had recorded $0.5 million, net of taxes of $0.3 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2004, 2003 and 2002 was not material. We expect to reclassify all amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" into the statement of income within the next twelve months when the forecasted sale of hedged production occurs.

At December 31, 2004, we had in place price floors in effect through the December 2005 contract month for natural gas, that cover a portion of our domestic natural gas production for January 2005 to December 2005. The natural gas price floors cover notional volumes of 4,000,000 MMBtu, with a weighted average floor price of $5.83 per MMBtu. Our natural gas price floors in place at December 31, 2004 are expected to cover approximately 30% to 35% of our domestic natural gas production from January 2005 to December 2005. At December 31, 2004, we also had in place crude oil price floors in effect through the March 2005 contract month, which cover a portion our domestic crude oil production for January 2005 to March 2005. The crude oil price floors cover notional volumes of 216,000 barrels, with a weighted average floor price of $37.00 per barrel. Our crude oil price floors in place at December 31, 2004 are expected to cover approximately 15% to 20% of our domestic crude oil production from January 2005 to March 2005.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas and crude oil production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the consolidated statement of income. The fair value of our derivatives is computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2004, was $1.8 million and is recognized on the accompanying balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells, with the remainder applied as a reduction to lease operating cost. Based on recent estimates, effective October 1, 2003, we began recording the supervision fee only as a reduction to general and administrative, net. The total amount of supervision fees charged to the wells we operate was $5.8 million in 2004, $5.1 million in 2003, and $5.3 million in 2002.

Inventories. We value inventories at the lower of cost or market value. Cost of crude oil inventory is determined using the weighted average method and all other inventory is accounted for using the first in, first out method ("FIFO"). The major categories of inventories, which are included in "Other current assets" on the accompanying balance sheets, are shown as follows:

	Balance at December 31, 2004 (000's)	Balance at December 31, 2003 (000's)
Materials, Supplies and Tubulars	$6,417	$2,966
Crude Oil	770	238
Total	$7,187	$3,204

Income Taxes. Under SFAS No. 109, "Accounting for Income Taxes," deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. The effective tax rate for 2004 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation, along with favorable corrections to tax basis amounts discovered while preparing the prior year's tax returns. These amounts were partially offset by higher deferred state income taxes. Income tax expense in 2003 includes a reduction from the U.S. statutory rate, primarily from the result of the currency exchange rate effect on the New Zealand deferred tax. This amount was partially offset by higher deferred state income taxes and other items. The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such laws can differ. The Company is currently evaluating the impact of the recently enacted American Jobs Creation Act of 2004. We do not believe this act will have a material impact in the near-term on our financial position or cash flow from operations.

Accounts Payable and Accrued Liabilities. Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at December 31, 2004 and 2003 are liabilities of approximately $6.9 million and $11.9 million, respectively, represents the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in the applicable bank accounts.

Cash and Cash Equivalents. We consider all highly liquid debt instruments with an initial maturity of three months or less to be cash equivalents.

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. During 2004, oil and gas sales to Shell, both domestically and in New Zealand, were $149.2 million, or 48% of total oil and gas sales. During 2003, oil and gas sales to Shell, both domestically and in New Zealand, were $31.1 million, or 15% of total oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were $23.5 million, or 11% of total oil and gas sales. During 2002, oil and gas sales to Eastex Crude Company were $25.4 million, or 18% of total oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were $14.6 million, or 10% of total oil and gas sales. Credit losses in 2004, 2003 and 2002 have been immaterial.

Environmental Costs. Our operations include activities that are subject to extensive federal and state environmental regulations. Costs associated with redemption projects, which are probable and quantifiable, are accrued in advance. Ongoing environmental compliance costs are expensed as incurred.

Restricted Assets. These balances include amounts deposited on plugging bonds in New Zealand, along with amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields domestically and in New Zealand.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities cash flows, commodity pricing environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, predominantly our portion of our "Deferred income taxes" and a portion of our "Asset Retirement Obligation" on the accompanying balance sheet. For accounts other than "Deferred income taxes," as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Price-risk management and other, net" on the accompanying statements of income. We recognize transaction gains and losses on "Deferred income taxes" in "Provision for Income Taxes" on the accompanying statement of income.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2004 and 2003, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2004 and 2003, the fair values of our senior subordinated notes due 2012 were $224.0 million, or 112.0% of face value, and $218.0 million, or 109% of face value, respectively. Based upon quoted market prices as of December 31, 2004, the fair value of our senior notes due 2011 was $162.4 million, or 108.25% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2004 and 2003. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2004.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Accumulated Other Comprehensive Income (Loss), Net of Income Tax. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2004, we recorded $0.5 million, net of taxes of $0.3 million, of derivative gains in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects for 2004 were as follows:

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2003	$ (420,847)	$ 151,505	$ (269,342)
Change in fair value of cash flow hedges	2,433,433	(890,636)	1,542,797
Effect of cash flow hedges settled during the period	(1,301,758)	478,968	(822,790)
Other comprehensive income at December 31, 2004	$ 710,828	$ (260,163)	$ 450,665

Total comprehensive income was $69.2 million, $29.8 million, and $11.7 million for 2004, 2003, and 2002, respectively.

Stock Based Compensation. We have two stock-based compensation plans, which are described more fully in Note 6. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. We issued restricted stock to employees for the first time in 2004 and recorded expense related to these shares of less than $0.1 million in "General and administrative, net" on the accompanying statements of income. No stock-based employee compensation cost is reflected in net income for employee stock options, as all options granted under those plans had an exercise price equal to the fair market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," our net income and earnings per share would have been adjusted to the following pro forma amounts:

		2004	2003	2002
Net Income:	As Reported	$68,450,917	$29,893,812	$11,923,227
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(3,557,541)	(4,112,455)	(4,451,799)
	Pro Forma	$64,893,376	$25,781,357	$ 7,471,428
Basic EPS:	As Reported	$2.46	$1.09	$0.45
	Pro Forma	$2.33	$0.94	$0.28
Diluted EPS:	As Reported	$2.41	$1.08	$0.45
	Pro Forma	$2.29	$0.94	$0.27

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions in 2004, 2003, and 2002, respectively: no dividend yield; expected volatility factors of 38.6%, 34.71%, and 73.72%; risk-free interest rates of 3.59%, 4.63%, and 4.74%; and expected lives of 5.4, 7.2, and 7.4 years. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003. Upon adoption of SFAS No. 143, we recorded an asset retirement obligation of \$8.9 million, an addition to oil and gas properties of \$2.0 million, and a non-cash charge of \$4.4 million (net of \$2.5 million of deferred taxes), which is recorded as a Cumulative Effect of Change in Accounting Principle. The cumulative charge to earnings took into consideration the impact of adopting SFAS No. 143 on previous full-cost ceiling tests. SFAS No. 143 is silent with respect to whether prior period ceiling tests should be reflected in the implementation entry calculation; however, management believes that any impairment on the properties should be reflected in the historical periods. Had we not considered the impact of adopting SFAS No. 143 on previous full-cost ceiling tests, the charge recognized would have been reduced. Excluding the Cumulative Effect of Change in Accounting Principle, the adoption of SFAS No. 143 reduced our 2003 net income by approximately \$0.6 million, or \$0.02 per diluted share. The following provides a roll-forward of our asset retirement obligation:

Asset Retirement Obligation recorded as of January 1, 2003	$ 8,934,320
Accretion expense for 2003	857,356
Liabilities incurred for new wells and facilities construction	608,166
Reductions due to sold and abandoned wells	(443,391)
Revisions in estimated cash flows	67,511
Increase due to currency exchange rate fluctuations	113,511
Asset Retirement Obligation as of December 31, 2003	$ 10,137,473
Accretion expense for 2004	673,654
Liabilities incurred for new wells and facilities construction	712,521
Liabilities incurred for Bay de Chene and Cote Blanche Island acquisitions	2,941,490
Reductions due to sold and abandoned wells	(1,083,174)
Revisions in estimated cash flows	4,195,474
Increase due to currency exchange rate fluctuations	61,698
Asset Retirement Obligation as of December 31, 2004	$ 17,639,136

At December 31, 2004 and 2003, approximately \$0.5 million and \$0.8 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets.

The pro forma effect for 2002, assuming adoption of SFAS No. 143 effective January 1, 2002, would have included a non-cash charge of \$3.7 million (net of \$2.1 million of deferred taxes), which would have been recorded as a Cumulative Effect of Change in Accounting Principle and recognition of an asset retirement obligation of \$6.2 million. The following table displays our pro forma results for the year ended December 31, 2002, had we adopted SFAS No. 143 effective January 1, 2002.

		Year Ended December 31, 2002
Net Income:	Actual – as reported	$ 11,923,227
	Pro Forma	$ 7,542,383
Basic EPS:	Actual – as reported	$ 0.45
	Pro Forma	$ 0.29
Diluted EPS:	Actual – as reported	$ 0.45
	Pro Forma	$ 0.28

New Accounting Pronouncements. In January 2003, the FASB issued Interpretation No. 46 (Revised December 2003) ("FIN 46R"), Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 consolidated financial statements (the "Interpretation"). The Interpretation significantly changes whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model—the variable interest model; which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. The Interpretation provides guidance for determining whether an entity lacks sufficient equity or its equity holders lack adequate decision-making ability. These variable interest entities ("VIEs") are covered by the Interpretation and are to be evaluated for consolidation based on their variable interests. These provisions applied immediately to variable interests in VIEs created after January 31, 2003, and to variable interests in special purpose entities for periods ending after December 15, 2003. The provisions apply for all other types of variable interests in VIEs for periods ending after March 15, 2004. We have no variable interests in VIEs, nor do we have variable interests in special purpose entities. The adoption of this interpretation had no impact on our financial position or results of operations.

In September and November 2004, the EITF discussed a proposed framework for addressing when a limited partnership should be consolidated by its general partner, EITF Issue 04-5. The proposed framework presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or protective rights would be considered substantive and preclude consolidation by the general partner and what limited partner's rights would be considered participating rights that would preclude consolidation by the general partner. The EITF tentatively concluded that for kick out rights to be considered substantive, the conditions specified in paragraph B20 of FIN 46R should be met. With regard to the definition of participating rights that would preclude consolidation by the general partner, the EITF concluded that the definition of those rights should be consistent with those in EITF Issue 96-16. The EITF also reached a tentative conclusion on the transition for Issue 04-05. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106 (SAB 106). SAB 106 expresses the SEC staff's views regarding SFAS No. 143 and its impact on both the full-cost ceiling test and the calculation of depletion expense. In accordance with SAB 106, beginning in the fourth quarter of 2004, undiscounted abandonment cost for future wells, not recorded at the present time but needed to develop the proved reserves in existence at the present time, should be included in the unamortized cost of oil and gas properties, net of related salvage value, for purposes of computing DD&A. The effect of including undiscounted abandonment costs of future wells to the undiscounted cost of oil and gas properties will increase depletion expense in future periods, however, we currently do not believe such increases will be material.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.
- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

We have elected to adopt the provisions of SFAS No. 123R on July 1, 2005 using the modified prospective method. As permitted by Statement 123, the Company currently accounts for share-based payments to employees using APB Opinion No. 25's intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R's fair value method is expected to have a significant impact on our result of operations. However, it will have no impact on our overall financial position. We currently use the Black-Scholes formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model upon the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share under "Stock Based Compensation." Statement No. 123R also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption. While the Company cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of excess tax deductions recognized were $2.0 million, $0.2 million, and $0.3 million in 2004, 2003 and 2002, respectively. These deductions resulted in an increase in operating cash flows, however, due to the Company's net operating tax loss position, deferred income taxes were reduced rather than actual cash taxes paid.

2. Earnings per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2004, 2003, and 2002 periods and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2004, 2003, and 2002:

	2004			2003			2002		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income and Share Amounts . . .	$68,450,917	27,822,413	$2.46	$29,893,812	27,357,579	$1.09	$ 11,923,227	26,382,906	$ 0.45
Dilutive Securities:									
Restricted Stock . . .	—	—		—	—		—	—	
Stock Options	—	524,860		—	203,360		—	372,700	
Diluted EPS:									
Net Income and Assumed Share Conversions	$68,450,917	28,347,273	$2.41	$29,893,812	27,560,939	$1.08	$ 11,923,227	26,755,606	$ 0.45

Options to purchase approximately 3.0 million shares at an average exercise price of $18.51 were outstanding at December 31, 2004, while options to purchase 3.2 million shares at an average exercise price of $16.37 were outstanding at December 31, 2003, and options to purchase 3.0 million shares at an average exercise price of $16.64 were outstanding at December 31, 2002. Approximately 1.1 million, 1.7 million, and 1.3 million options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2004, 2003, and 2002, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 70,900 shares, which were issued in 2004, were not included in the computation of Diluted EPS for the year ended December 31, 2004, because these restricted stock grants were antidilutive in that the amount of future compensation expense per share recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during that period. Other restricted stock grants of 30,000 shares, which were issued in 2004, were not included in the computation of Diluted EPS for the year ended December 31, 2004, as performance conditions surrounding the vesting of these shares had not occurred.

3. Provision for Income Taxes

Income before taxes is as follows:

	Year Ended December 31,		
	2004	2003	2002
United States . . .	$ 86,000,508	$ 38,955,405	$ 12,889,583
Foreign	15,439,734	11,783,773	5,518,706
Total	$ 101,440,242	$ 50,739,178	$ 18,408,289

The following is an analysis of the consolidated income tax provision:

	Year Ended December 31,		
	2004	2003	2002
Current	$ 469,717	$ 164,284	$ 2,338
Deferred:			
Domestic	31,137,643	14,386,868	4,870,239
Foreign	1,381,965	1,917,362	1,612,485
Total Deferred	32,519,608	16,304,230	6,482,724
Total	$ 32,989,325	$ 16,468,514	$ 6,485,062

Reconciliations of income taxes computed using the U.S. Federal statutory rate to the effective income tax rates are as follows:

	2004	2003	2002
Income taxes computed at U.S. statutory rate (35%)	$ 35,504,086	$ 17,758,712	$ 6,442,901
State tax provisions, net of federal benefits	1,140,499	373,992	323,902
Effect of foreign operations	317,967	(235,675)	(110,374)
Currency exchange impact on foreign tax calculation	(2,516,120)	(2,893,655)	(208,688)
Correction to tax basis of foreign oil and gas properties	(1,378,900)	—	—
Change in estimate for deferred Louisiana income taxes, net of federal benefits . . .	858,943	1,216,105	—
Other, net	(937,150)	249,035	37,321
Provision for income taxes	$ 32,989,325	$ 16,468,514	$ 6,485,062
Effective rate	32.5%	32.5%	35.2%

As noted in the above table, the most significant contributor to the difference between the federal statutory rate and the effective rate for 2004 and 2003 is attributed to currency exchange impact on the foreign income tax calculation. The Company's New Zealand subsidiaries use the U.S. Dollar as their functional currency for financial reporting purposes, but income taxes are calculated from New Zealand Dollar financial statements and re-measured into U.S. Dollars. Volatility in exchange rates creates variable results when computing income in different currencies. The most significant difference in the relative income computations for 2004 and 2003 was attributable to depreciation, depletion, and amortization (DD&A). Because of the relative strengthening of the New Zealand Dollar vs. the U.S. Dollar, the value of the tax DD&A deduction reflects the relative appreciation in the New Zealand Dollar tax basis of amortizable assets vs. the historical U.S. Dollar investment costs. As a result, taxable income (and accordingly income tax expense) computed in New Zealand Dollars and then converted to U.S. Dollars at the average exchange rates for each respective year was significantly less than net income computed in the subsidiaries' U.S. Dollar financial statements. Additionally, the deferred tax asset is revalued at the ending exchange rate for each period. This revaluation also resulted in favorable adjustments for 2004, 2003, and 2002. In aggregate, the Company recognized foreign exchange benefits to tax expense in the amounts of $2.5 million, $2.9 million, and $0.2 million for 2004, 2003, and 2002, respectively. If exchange rates remain volatile in the future significant fluctuations in the impact on the Company's effective tax rate are likely to continue.

In addition to the exchange impact, the Company also had a favorable adjustment in 2004 from a correction in the tax basis of the TAWN assets. The majority of these adjustments were discovered when preparing the 2002 New Zealand tax returns which were due and filed in March 2004. Additionally, the basis adjustments resulted in an increase in the acquired deferred tax asset balance of $1.1 million.

The primary unfavorable differences between the federal statutory and the effective rate are attributable to state income taxes (computed net of the offsetting federal benefit), which were $1.1 million, $0.4 million and $0.3 million for 2004, 2003, and 2002, respectively. Additional, the Company recorded adjustments to the cumulative Louisiana deferred tax liability in the amounts of $0.9 million and $1.2 million during 2004 and 2003, respectively due to its increased level of business activity in Louisiana. The Company calculates its Louisiana income tax using the "apportionment" accounting method. Under apportionment accounting, total federal taxable income is allocated based on the proportional level of U.S. business activity within the state. Due to the relative increase in the Company's Louisiana activity, the Company increased its estimate of future Louisiana taxable income that will result from the reversal of prior years' timing differences. The 2004 increase was primarily due to acquisitions and development activities in Lake Washington. The 2003 increase was primarily due to development activities in Lake Washington.

The New Zealand statutory rate is 33%, which resulted in differences of $0.3 million, $0.2 million, and $0.1 million for 2004, 2003, and 2002 respectively vs. the U.S. statutory rate. The 2004 favorable rate impact is more than offset by a $0.6 million accrual for taxes expected to be incurred on a planned dividend from the Company's New Zealand subsidiaries. Except for a limited dividend tied to a cost of capital computation, the Company does not compute a provision for U.S. taxes on the undistributed earnings of our New Zealand subsidiaries as management has plans to reinvest such earnings outside of the United States indefinitely. If, in the future, these earnings are distributed into the U.S. in the form of dividends or otherwise, we may be subject to U.S. income taxes and New Zealand withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable if such remittances occur. Presently, there are no foreign tax credits available to reduce the U.S. taxes on such amounts if repatriated.

The Company is currently evaluating the possibility of utilizing a special one-time tax deduction relating to the repatriation of foreign earnings created by the American Jobs Creation Act of 2004. To be eligible the Company would need to develop a qualified domestic reinvestment plan. As of this date the Company has not yet completed this evaluation or developed a reinvestment plan. However, as of December 31, 2004 the Company is in a cumulative tax loss position with respect to its foreign operations. The Company believes the maximum available deduction would be limited to the 2005 taxable earnings of its foreign subsidiaries, if any. The Company will not be in a position to make a reasonable estimate until later in the year as to how much, if any, income will be available to repatriate at the reduced rate.

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2004 and 2003, were as follows:

	2004	2003
Deferred tax assets:		
Alternative minimum tax credits (domestic)	$ (2,579,399)	$ (1,979,399)
Carryover items (domestic)	(47,600,945)	(53,006,919)
Acquired deferred tax asset (foreign)	(3,407,885)	(3,802,435)
Carryover items (foreign)	(37,852,559)	(28,294,320)
Other (domestic)	(167,475)	(152,725)
Total deferred tax assets	$ (91,608,263)	$ (87,235,798)
Deferred tax liabilities:		
Domestic oil and gas exploration and development costs	$ 121,893,202	$ 98,092,129
Foreign oil and gas exploration and development costs	39,594,386	30,160,846
Scheduled dividend from foreign subsidiary	626,762	—
Other (domestic)	934,435	575,596
Total deferred tax liabilities	$ 163,048,785	$ 128,828,571
Net deferred tax liabilities	$ 71,440,522	$ 41,592,773

The total change in the net deferred liability from 2003 to 2004 was $29.8 million. Increases in the liability were attributable to deferred tax expense of $32.5 million plus $0.4 million for the tax effect of unrealized hedging gains. Unrealized hedging gains and losses are recorded net of tax as other comprehensive income (loss) adjustments to equity. Reductions were made to the net liability for the tax benefit of stock compensation deductions of $2.0 million, which are recorded as additions to paid-in-capital, and $1.1 million for an adjustment to the foreign acquired deferred tax asset.

The tax basis of the assets of Southern Petroleum (NZ) Exploration Limited ("Southern NZ") on the acquisition date exceeded the cash purchase price paid by SENZ to acquire this entity. To account for the future tax benefits of this additional basis, SENZ recorded a deferred tax asset of $4.9 million. The asset is being amortized over the period in which the tax amortization is deducted. The remaining asset value at December 31, 2003, was $3.8 million. During 2004 the deferred tax asset was increased by $1.1 million as noted previously. Amortization during 2004 was $1.5 million. The other foreign carryover asset is attributable to cumulative New Zealand net operating losses of $114.7 million. New Zealand tax net operating losses do not expire.

At December 31, 2004, the Company had alternative minimum tax credits of $2.6 million that carry forward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the alternative minimum tax otherwise due.

The domestic deferred tax carryover items are attributable to expected future tax benefits in the amounts of $40.0 million for federal net operating losses, $1.6 million for State of Louisiana net operating losses and $6.0 million net for capital losses. The gross capital loss asset is $6.5 million less a $.5 million impairment. At December 31, 2004, cumulative estimated federal net operating losses were $113.9 million, which will expire between 2018 and 2023. Louisiana estimated net operating losses total $44.8 million and will expire between 2013 and 2018.

The Company has not recorded any valuation allowance against the deferred tax assets attributable to net operating loss carryovers at December 31, 2004 and 2003, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts.

In 2002 we recognized a capital loss of approximately $18.6 million as the result of the liquidation of our partnerships. This loss can only be utilized to offset capital gains and will expire in 2007. The Company plans to sell one or more of its oil and gas properties during the next few years that will generate sufficient capital gains to utilize the loss carry over. To generate capital gains from these dispositions, the sales proceeds must exceed the Company's total investment in the properties. Company management has identified several qualified properties that have estimated current market values well in excess of the total original costs. Management believes that it is more likely than not that the Company will fully utilize the capital loss carryover. If the Company is unable to complete the sale of these properties at the prices it has estimated to be the fair market value, then a significant portion of the capital loss carryover could expire before it is utilized. During 2004 the Company recorded a valuation allowance of $0.5 million, primarily for incremental state income tax expenses that it expects to incur as a result of the planned property dispositions.

4. Long-Term Debt

Our long-term debt as of December 31, 2004 and 2003, is as follows:

	2004	2003
Bank Borrowings	$ 7,500,000	$ 15,900,000
10-1/4% senior subordinated notes due 2009	—	124,354,783
7-5/8% senior notes due 2011	150,000,000	—
9-3/8% senior subordinated notes due 2012	200,000,000	200,000,000
Long-Term Debt	$ 357,500,000	$ 340,254,783

Bank Borrowings. At December 31, 2004, we had $7.5 million in outstanding borrowings under our $400.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2008. At December 31, 2003, we had $15.9 million in outstanding borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (5.25% at December 31, 2004) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. All amounts borrowed at December 31, 2004 were at the bank's prime rate. In June 2004, we increased, renewed and extended this credit facility, increasing the facility to $400 million from $300 million and extending its expiration to October 1, 2008 from October 1, 2005. The other terms of the credit facility, such as the borrowing base amount and commitment amount, stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011 or 9-3/8% senior subordinated notes due 2012. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective November 1, 2004. We requested that the commitment amount with our bank group be reduced to $150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in May 2005.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2004, $1.6 million in 2003, and $3.6 million in 2002. The amount of commitment fees included in interest expense, net was $0.5 million in 2004 and $0.6 million in both 2003 and 2002.

Senior Subordinated Notes Due 2009. These notes consisted of $125.0 million of 10-1/4% senior subordinated notes due August 2009, which were issued at 99.236% of the principal amount on August 4, 1999, and were scheduled to mature on August 1, 2009. These notes were unsecured senior subordinated obligations with interest payable semiannually, on February 1 and August 1. In June 2004, we repurchased $32.1 million of these notes pursuant to a tender offer. In July 2004, we repurchased an additional $0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining $92.5 million in outstanding notes. In 2004, we recorded a charge of $9.5 million related to the repurchase of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statement of income. The costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount, and approximately $0.2 million of other costs.

Interest expense on the 10-1/4% senior subordinated notes due 2009, including amortization of debt issuance costs and discount, totaled $7.4 million in 2004 and $13.2 million in both 2003 and 2002.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes due 2011, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we may redeem up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $6.2 million in 2004.

Senior Subordinated Notes Due 2012. These notes consist of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 11, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility. Interest on these notes is payable semiannually on May 1 and November 1, with the first interest payment on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we may redeem up to 33.33% of these notes with the net proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, plus accrued and unpaid interest. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these subordinated notes due 2012.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $19.2 million in 2004, $19.1 million in 2003 and $13.5 million in 2002.

The aggregate maturities on our long-term debt are $0, $0, $0, $7.5 million, $0, and $350.0 million for 2005, 2006, 2007, 2008, 2009, and thereafter, respectively.

We have capitalized interest on our unproved properties in the amount of $6.5 million, $6.8 million, and $7.0 million, in 2004, 2003, and 2002, respectively.

5. Commitments and Contingencies

Total rental and lease expenses were $2.4 million in 2004, $2.2 million in 2003, and $1.9 million in 2002 and are included in "General and administrative, net" on our accompanying consolidated statements of income. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $2.5 million for 2005, $2.6 million for 2006, $2.5 million for 2007, $2.5 million for 2008, $2.3 million in 2009, and $13.0 million thereafter or $25.4 million in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas, and in New Zealand.

In the ordinary course of business, we have entered into agreements with drilling and seismic contractors for such services. The remaining commitments at December 31, 2004 for these services totaled $4.4 million and these services are expected to be provided in 2005.

As of December 31, 2004, we were the managing general partner of six private limited partnerships. Because we serve as the general partner of these entities, under state partnership law we are contingently liable for the liabilities of these partnerships, which liabilities are not material for any of the periods presented in relation to the partnerships' respective assets.

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders' Equity

Common Stock. During the first quarter of 2002, we issued 1.725 million shares of common stock at a price of $18.25 per share pursuant to a public underwriting offering. Gross proceeds from this offering were $31.5 million, with issuance costs of $1.0 million.

Stock-Based Compensation Plans. We have two stock option plans that awards are currently granted under, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants will be made under the 1990 Stock Compensation Plan, which was replaced by the 2001 Omnibus Stock Compensation Plan, although options remain outstanding under such plan and are accordingly included in the tables below. In addition, we have an employee stock purchase plan.

Under the 2001 plan, incentive stock options and other options and awards may be granted to employees to purchase shares of common stock. Under the 1990 non-qualified plan, non-employee members of our Board of Directors are automatically granted options to purchase shares of common stock on a formula basis. Both plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Unless otherwise provided, options become exercisable for 20% of the shares on the first anniversary of the grant of the option and are exercisable for an additional 20% per year thereafter. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under this plan also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying Statement of Stockholders' Equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. The plan year is from June 1 to the following May 31. The first year of the plan commenced June 1, 1993. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Under this plan for the last three years, we have issued 50,418 shares at a price range of $9.98 to $10.83 in 2004, 56,574 shares at a price range of $6.80 to $11.85 in 2003, and 9,801 shares at a price of $12.47 in 2002. As of December 31, 2004, 245,635 shares remained available for issuance under this plan.

The following is a summary of our stock options under these plans as of December 31, 2004, 2003, and 2002:

	2004		2003		2002	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	3,238,611	$ 16.37	3,018,505	$ 16.64	2,639,504	$ 17.44
Options granted	415,744	$ 23.36	504,014	$ 13.20	585,055	$ 12.32
Options canceled	(64,866)	$ 21.85	(110,901)	$ 21.02	(84,254)	$ 23.37
Options exercised[1]	(590,821)	$ 9.83	(173,007)	$ 8.85	(121,800)	$ 8.61
Options outstanding, end of period	2,998,668	$ 18.51	3,238,611	$ 16.37	3,018,505	$ 16.64
Options exercisable, end of period	1,542,571	$ 17.78	1,714,789	$ 15.00	1,480,490	$ 13.71
Options available for future grant, end of period	89,278		494,925		419,845	
Estimated weighted average fair value per share of options granted during the year	$9.51		$6.93		$9.55	

[1]The option plans allow for the use of a "stock swap" in lieu of a cash exercise, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid "stock swap." Options issued under a "stock swap" also include a reload feature where additional options are granted at the then current market price when mature shares of Swift stock are used to satisfy the exercise price of an existing stock option grant. The terms of the plans provide that the mature shares delivered as full or partial payment in a "stock swap" shall again be available for awards under the plans. The options exercised above include 81,716, 30,200 and 8,805 shares in 2004, 2003, and 2002, respectively, related to "stock swap" shares that were also reloaded.

The following table summarizes information about stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/04	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/04	Wtd. Avg. Exercise Price
$ 7.00 to $17.99	1,723,401	6.1	$ 11.64	955,298	$ 10.76
$18.00 to $28.99	598,044	7.0	$ 23.23	169,924	$ 22.60
$29.00 to $41.00	677,223	6.2	$ 31.84	417,349	$ 31.89
$ 7.00 to $41.00	2,998,668	6.3	$ 18.51	1,542,571	$ 17.78

Restricted Stock. In 2004, the Company issued the rights to 70,900 shares of restricted stock to employees. These shares vest over a five-year period and remain subject to forfeiture if vesting conditions are not met. In accordance with APB Opinion No. 25, we recognize unearned compensation in connection with the grant of restricted shares equal to the fair value of our common stock on the date of grant. The fair value of these shares when issued in 2004 was approximately $25 per share and resulted in an increase in "Additional paid-in capital" and "Unearned compensation" on the accompanying balance sheet of $1.8 million. As restricted shares vest, we reduce unearned compensation and recognize compensation expense. In 2004, we recorded expense related to these shares of less than $0.1 million in "General and administrative, net" on the accompanying statements of income.

In 2004, we also issued the rights to 30,000 shares of restricted stock to non-employees. These shares vest over a two-year period and remain subject to forfeiture if performance conditions are not met within that period. This issuance is accounted for under FAS No. 123 and as such a measurement date for assessing fair value of this grant has not been achieved. We recognized approximately $0.2 million of compensation cost in 2004 related to these shares. The non-employee performs work that is capitalized to unproved properties, and as such the compensation cost recognized in 2004 was recorded to "Unproved properties" on the accompanying balance sheets.

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan ("ESOP") effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a five-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2004, 2003, and 2002, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2004, 2003, and 2002, and were made all in common stock, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The shares of common stock contributed to the ESOP plan totaled 6,911, 11,870, and 18,711 shares for the 2004, 2003, and 2002 contributions, respectively.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $0.7 million for 2004 and $0.6 million for each of the years ended December 31, 2003 and 2002, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The contributions in 2004, 2003, and 2002 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 24,513, 34,280, and 64,490 shares for the 2004, 2003, and 2002 contributions, respectively.

Common Stock Repurchase Program. In March 1997, our Board of Directors approved a common stock repurchase program that terminated as of June 30, 1999. Under this program, we spent approximately $13.3 million to acquire 927,774 shares in the open market at an average cost of $14.34 per share. At December 31, 2004, 480,868 shares remain in treasury (net of 446,906 shares used to fund ESOP, 401(k) contributions and acquisitions) with a total cost of $6.9 million and are included in "Treasury stock held, at cost" on the accompanying balance sheet.

Shareholder Rights Plan. In August 1997, our board of directors declared a dividend of one preferred share purchase right on each outstanding share of Swift Energy common stock. The rights are not currently exercisable but would become exercisable if certain events occurred relating to any person or group acquiring or attempting to acquire 15% or more of our outstanding shares of common stock. Thereafter, upon certain triggers, each right not owned by an acquirer allows its holder to purchase Swift securities with a market value of two times the $150 exercise price.

7. Related-Party Transactions

We have been the operator of a number of properties owned by private limited partnerships and, accordingly, charge these entities operating fees. The operating supervision fees charged to the partnerships totaled approximately $0.2 million in both 2004 and 2003 and $0.3 million in 2002 and are recorded as reductions of "General and administrative, net." We also have been reimbursed for administrative and overhead costs incurred in conducting the business of the private limited partnerships, which totaled approximately $0.2 million, $0.4 million, and $1.0 million in 2004, 2003, and 2002, respectively, and are recorded as reductions in "General and administrative, net." Included in "Accounts receivable" and "Accounts payable and accrued liabilities" on the accompanying balance sheets is less than $0.1 million and $1.1 million, respectively, in receivables from and payables to the partnerships at December 31, 2004.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled by the sister of the Company's Chairman and Vice Chairman of the Board. The sister and brother-in-law of Messrs. A. E. Swift and V. Swift also own a substantial majority of Tec-Com. In 2004, 2003 and 2002, we paid approximately $0.4 million per year to Tec-Com for such services pursuant to the terms of the contract between the parties. The contract was renewed June 30, 2004 on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services. As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee's charter.

8. Foreign Activities

As of December 31, 2004, our gross capitalized oil and gas property costs in New Zealand totaled approximately $243.2 million. Approximately $209.8 million has been included in the "Proved properties" portion of our oil and gas properties, while $33.4 million is included as "Unproved properties." Our functional currency in New Zealand is the U.S. Dollar. Net assets of our New Zealand operations total $197.4 million at December 31, 2004. Our expenditures on oil and gas property in New Zealand were approximately $36.5 million in 2004.

9. Acquisitions and Dispositions

New Zealand

Through our subsidiary, Swift Energy New Zealand Limited ("SENZ"), we acquired Southern Petroleum (NZ) Exploration Limited ("Southern NZ") in January 2002 for approximately $51.4 million in cash. We allocated $36.1 million of the acquisition price to "Proved properties," $10.0 million to "Unproved properties," $4.9 million to "Deferred income taxes," and $0.4 million to "Other current assets" on our consolidated balance sheet. Southern NZ was an affiliate of Shell New Zealand and owns interests in four onshore producing oil and gas fields, hydrocarbon processing facilities, and pipelines connecting the fields and facilities to export terminals and markets. These assets fit strategically with our existing assets in New Zealand. This acquisition was accounted for by the purchase method of accounting. The revenues and expenses from these TAWN properties have been included in our consolidated statements of income from the date of acquisition forward. In conjunction with this TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which included our Rimu/Kauri areas and the Rimu Production Station. This option was not exercised and expired on May 15, 2002.

In March 2002, we purchased through our subsidiary, SENZ, all of the New Zealand assets owned by Antrim for 220,000 shares of Swift Energy common stock, which we held in treasury, valued at $4.2 million and an effective date adjustment of approximately $0.5 million in cash for total consideration of $4.7 million. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716.

In September 2002, we purchased through our subsidiary, SENZ, Bligh's 5% working interest in permit 38719 and 5% interest in the Rimu petroleum mining permit 38151, along with their 3.24% working interest in the four TAWN petroleum mining licenses for 300,000 shares of Swift Energy common stock valued at $3.9 million and $2.7 million in cash for total consideration of $6.6 million.

Domestic

In December 2004 we acquired interests in two fields in South Louisiana, the Bay de Chene and Cote Blanche Island fields. We paid approximately $27.7 million in cash for these interests. After taking into account internal acquisition costs of $2.8 million, our total cost was $30.5 million. We allocated $27.8 million of the acquisition price to "Proved properties" and $5.1 million to "Unproved properties"; we also recorded $0.5 million to "Restricted assets" and recorded a liability of $2.9 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward, however, given the acquisition was in late December 2004, these amounts were immaterial.

Russia

In 1993, we entered into a Participation Agreement with Senega, a Russian Federation joint stock company, to assist in the development and production of reserves from two fields in Western Siberia and received a 5% net profits interest. We also purchased a 1% net profits interest. Our investment in Russia was fully impaired in the third quarter of 1998. In March 2002, we received $7.5 million for our investment in Russia. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all $10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a $7.3 million non-recurring gain on asset disposition in the first quarter of 2002, and is included in our accompanying statements of income.

10. Segment Information

The Company has two reportable segments, one domestic and one foreign, which are in the business of crude oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate our performance based on profit or loss from oil and gas operations before gain on asset disposition, price-risk management and other, net, general and administrative, net, interest expense, net and debt retirement costs. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	2004		
	Domestic	New Zealand	Total
Oil and gas sales	$ 258,663,936	$ 52,621,236	$ 311,285,172
Costs and Expenses:			
Depreciation, depletion, and amortization	(62,283,350)	(19,297,478)	(81,580,828)
Accretion of asset retirement obligation	(505,174)	(168,480)	(673,654)
Lease operating cost	(30,191,889)	(11,022,367)	(41,214,256)
Severance and other taxes	(26,713,592)	(3,687,701)	(30,401,293)
Income from oil and gas operations	$ 138,969,931	$ 18,445,210	$ 157,415,141
Price-risk management and other, net			(1,008,398)
General and administrative, net			(17,787,125)
Interest expense, net			(27,643,108)
Debt retirement costs			(9,536,268)
Income Before Income Taxes and Change in Accounting Principle			$ 101,440,242
Property and Equipment, net	$ 731,890,068	$ 191,548,092	$ 923,438,160
Total Assets	778,611,100	211,962,047	990,573,147
Capital Expenditures	$ 162,535,617	$ 35,755,820	$ 198,291,437

	2003		
	Domestic	New Zealand	Total
Oil and gas sales	$ 164,167,390	$ 46,865,249	$ 211,032,639
Costs and Expenses:			
Depreciation, depletion, and amortization	(44,645,939)	(18,426,118)	(63,072,057)
Accretion of asset retirement obligation	(623,948)	(233,408)	(857,356)
Lease operating cost	(24,022,412)	(9,810,786)	(33,833,198)
Severance and other taxes	(15,290,669)	(3,742,935)	(19,033,604)
Income from oil and gas operations	$ 79,584,422	$ 14,652,002	$ 94,236,424
Price-risk management and other, net			(2,131,656)
General and administrative, net			(14,097,066)
Interest expense, net			(27,268,524)
Income Before Income Taxes and Change in Accounting Principle			$ 50,739,178
Property and Equipment, net	$ 641,366,888	$ 174,440,115	$ 815,807,003
Total Assets	672,721,551	187,116,993	859,838,544
Capital Expenditures	$ 114,443,475	$ 30,059,705	$ 144,503,180

	2002		
	Domestic	New Zealand	Total
Oil and gas sales	$ 112,065,003	$ 29,130,710	$ 141,195,713
Costs and Expenses:			
Depreciation, depletion, and amortization	(43,660,843)	(12,563,549)	(56,224,392)
Lease operating costs	(23,308,444)	(5,610,414)	(28,918,858)
Severance and other taxes	(9,780,514)	(2,797,940)	(12,578,454)
Income from oil and gas operations	$ 35,315,202	$ 8,158,807	$ 43,474,009
Gain on asset disposition			7,332,668
Price-risk management and other, net			1,441,430
General and administrative, net			(10,564,849)
Interest expense, net			(23,274,969)
Income Before Income Taxes and Change in Accounting Principle			$ 18,408,289
Property and Equipment, net	$ 565,149,393	$ 160,360,061	$ 725,509,454
Total Assets	594,627,972	172,377,887	767,005,859
Capital Expenditures	$ 59,981,376	$ 95,252,547	$ 155,233,923

Supplemental Information (Unaudited)

Swift Energy Company and Subsidiaries

Capitalized Costs. The following table presents our aggregate capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, and amortization:

	Total	Domestic	New Zealand
December 31, 2004:			
Proved oil and gas properties	$1,479,681,903	$1,271,354,490	$ 208,327,413
Unproved oil and gas properties	80,121,509	46,751,416	33,370,093
	1,559,803,412	1,318,105,906	241,697,506
Accumulated depreciation, depletion, and amortization	(641,917,990)	(590,906,014)	(51,011,976)
Net capitalized costs	$ 917,885,422	$ 727,199,892	$ 190,685,530
December 31, 2003:			
Proved oil and gas properties	$1,305,110,582	$1,135,615,117	$ 169,495,465
Unproved oil and gas properties	67,557,969	31,802,621	35,755,348
	1,372,668,551	1,167,417,738	205,250,813
Accumulated depreciation, depletion, and amortization	(560,961,013)	(529,272,658)	(31,688,355)
Net capitalized costs	$ 811,707,538	$ 638,145,080	$ 173,562,458

Of the $46.7 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2004, excluded from the amortizable base, $30.3 million was incurred in 2004, $2.9 million was incurred in 2003, $2.5 million was incurred in 2002, and $11.1 million was incurred in prior years. When we are in an active drilling mode, we evaluate the majority of these unproved costs within a two to four year time frame.

Of the $33.4 million of New Zealand Unproved property costs at December 31, 2004, excluded from the amortizable base, $3.7 million was incurred in 2004, $8.3 million was incurred in 2003, $17.0 million was incurred or acquired in 2002, and $4.4 million was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved properties as of December 31, 2004 and 2003, as we adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" effective January 1, 2003.

Costs Incurred. The following table sets forth costs incurred related to our oil and gas operations:

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 31,771,094	$ 31,771,094	$ —
Lease acquisitions and prospect costs[1]	34,545,393	27,713,059	6,832,334
Exploration	17,430,265	16,714,982	715,283
Development	105,947,485	78,163,289	27,784,196
Total acquisition, exploration, and development[2]	$ 189,694,237	$ 154,362,424	$ 35,331,813
Processing plants	$ 1,283,515	$ 147,317	$ 1,136,198
Field compression facilities	1,028,091	1,028,091	—
Total plants and facilities	$ 2,311,606	$ 1,175,408	$ 1,136,198
Total costs incurred[3]	$ 192,005,843	$ 155,537,832	$ 36,468,011

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 1,942,868	$ 1,635,316	$ 307,552
Lease acquisitions and prospect costs[1]	18,869,099	12,440,144	6,428,955
Exploration	14,467,455	11,789,700	2,677,755
Development	116,451,112	100,549,351	15,901,761
Total acquisition, exploration, and development[2]	$ 151,730,534	$ 126,414,511	$ 25,316,023
Processing plants	$ 6,192,199	$ 907,771	$ 5,284,428
Field compression facilities	3,521,522	3,521,522	—
Total plants and facilities	$ 9,713,721	$ 4,429,293	$ 5,284,428
Total costs incurred[3]	$ 161,444,255	$ 130,843,804	$ 30,600,451

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 64,229,283	$ 5,415,932	$ 58,813,351
Lease acquisitions and prospect costs[1]	16,009,939	10,789,876	5,220,063
Exploration	18,395,335	7,571,215	10,824,120
Development	47,407,087	40,366,378	7,040,709
Total acquisition, exploration, and development[2]	$ 146,041,644	$ 64,143,401	$ 81,898,243
Processing plants	$ 7,845,520	$ 1,313,299	$ 6,532,221
Field compression facilities	2,251,247	2,251,247	—
Total plants and facilities	$ 10,096,767	$ 3,564,546	$ 6,532,221
Total costs incurred[3]	$ 156,138,411	$ 67,707,947	$ 88,430,464

[1]These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2004, 2003, and 2002 were $17,811,217, $20,702,276, and $23,454,234, respectively.

[2]Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $13.1 million, $11.5 million, and $10.7 million in 2004, 2003, and 2002, respectively. In addition, total includes $6.5 million, $6.8 million, and $7.0 million in 2004, 2003, and 2002, respectively, of capitalized interest on unproved properties.

[3]Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2004 and 2003, as we adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" effective January 1, 2003.

Results of Operations.

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Oil and gas sales	$311,285,172	$258,663,936	$ 52,621,236
Lease operating cost	(41,214,256)	(30,191,889)	(11,022,367)
Severance and other taxes	(30,401,293)	(26,713,592)	(3,687,701)
Depreciation and depletion	(80,504,043)	(61,478,364)	(19,025,679)
Accretion of asset retirement obligation	(673,654)	(505,174)	(168,480)
	158,491,926	139,774,917	18,717,009
Provision for income taxes	53,093,022	51,576,944	1,516,078
Results of producing activities	$105,398,904	$ 88,197,973	$ 17,200,931
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.38	$ 1.46	$ 1.17

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Oil and gas sales	$211,032,639	$164,167,390	$ 46,865,249
Lease operating cost	(33,833,198)	(24,022,412)	(9,810,786)
Severance and other taxes	(19,033,604)	(15,290,669)	(3,742,935)
Depreciation and depletion	(62,037,680)	(43,818,709)	(18,218,971)
Accretion of asset retirement obligation	(857,356)	(623,948)	(233,408)
	95,270,801	80,411,652	14,859,149
Provision for income taxes	32,321,635	29,696,023	2,625,612
Results of producing activities	$ 62,949,166	$ 50,715,629	$ 12,233,537
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.17	$ 1.30	$ 0.94

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Oil and gas sales	$141,195,713	$112,065,003	$ 29,130,710
Lease operating cost	(28,918,858)	(23,308,444)	(5,610,414)
Severance and other taxes	(12,578,454)	(9,780,514)	(2,797,940)
Depreciation and depletion	(55,254,467)	(42,807,364)	(12,447,103)
	44,443,934	36,168,681	8,275,253
Provision for income taxes	15,860,064	13,129,231	2,730,833
Results of producing activities	$ 28,583,870	$ 23,039,450	$ 5,544,420
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.11	$ 1.25	$ 0.80

These results of operations do not include the losses from our hedging activities of $1.3 million, $2.8 million, and $0.2 million for 2004, 2003, and 2002, respectively. Our lease operating costs per Mcfe produced were $0.71 in 2004, $0.64 in 2003, and $0.58 in 2002.

The accretion of asset retirement obligation has been included in the 2004 and 2003 periods, as we adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" effective January 1, 2003.

We used our effective tax rate in each country to compute the provision for income taxes in each year presented.

Supplemental Reserve Information. The following information presents estimates of our proved oil and gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 100% of our proved reserves. Gruy's audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of production histories and other geological, economic, and engineering data provided by Swift. Where Gruy had material disagreements with Swift reserve estimates, we revised our estimates to be in agreement. Gruy's report dated January 27, 2005, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2004, and includes definitions and assumptions that served as the basis for the audit of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

Estimates of Proved Reserves

	Total		Domestic		New Zealand	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)
Proved reserves as of December 31, 2001	324,912,125	53,482,636	288,489,500	42,564,733	36,422,625	10,917,903
Revisions of previous estimates[1]	(29,972,714)	5,298,439	(29,470,419)	8,675,082	(502,295)	(3,376,643)
Purchases of minerals in place	51,940,044	3,711,948	226,245	24,207	51,713,799	3,687,741
Sales of minerals in place	(3,839,124)	(464,490)	(3,839,124)	(464,490)	—	—
Extensions, discoveries, and other additions	10,822,919	12,180,558	197,919	11,304,782	10,625,000	875,776
Production	(27,131,578)	(3,770,128)	(15,780,059)	(3,074,674)	(11,351,519)	(695,454)
Proved reserves as of December 31, 2002	326,731,672	70,438,963	239,824,062	59,029,640	86,907,610	11,409,323
Revisions of previous estimates[1]	(6,445,114)	4,975,920	(1,418,312)	3,497,022	(5,026,802)	1,478,898
Purchases of minerals in place	273,623	35,472	273,623	35,472	—	—
Sales of minerals in place	(3,984,209)	(228,505)	(3,984,209)	(228,505)	—	—
Extensions, discoveries, and other additions	47,231,609	9,730,665	21,370,151	8,018,766	25,861,458	1,711,899
Production	(28,002,719)	(4,192,612)	(13,744,040)	(3,336,702)	(14,258,679)	(855,910)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015,693	93,483,587	13,744,210
Revisions of previous estimates[1]	(3,306,705)	(1,117,715)	(1,619,531)	695,274	(1,687,174)	(1,812,989)
Purchases of minerals in place	9,808,953	5,602,508	9,808,953	5,602,508	—	—
Sales of minerals in place	(2,524,760)	(44,803)	(2,524,760)	(44,803)	—	—
Extensions, discoveries, and other additions	2,205,670	830,111	2,205,670	830,111	—	—
Production	(23,741,726)	(5,762,796)	(12,299,772)	(4,959,740)	(11,441,954)	(803,056)
Proved reserves as of December 31, 2004	318,246,294	80,267,208	237,891,835	69,139,043	80,354,459	11,128,165
Proved developed reserves:[2]						
December 31, 2001	181,651,578	23,759,574	167,401,736	20,393,142	14,249,842	3,366,432
December 31, 2002	233,514,572	35,928,395	149,731,562	26,530,112	83,783,010	9,398,283
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767,983	71,946,586	6,757,383
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628,873	52,761,709	5,408,979

[1]*Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates,* volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2004, were based upon prices in effect at year-end. Our hedges at year-end 2004 consisted of oil and natural gas price floors with strike prices mostly lower than the period end price and thus would not materially affect prices used in these calculations. The weighted average of 2004 year-end prices for total, domestic, and New Zealand were \$5.16, \$5.87, and \$3.07 per Mcf of natural gas, \$41.07, \$42.21, and \$33.60 per barrel of oil, and \$25.48, \$26.49 and \$20.48 per barrel of NGL, respectively. This compares to \$4.56, \$5.53, and \$2.04 per Mcf of natural gas, \$30.16, \$30.88, and \$26.78 per barrel of oil, and \$20.61, \$21.81 and \$14.10 per barrel of NGL as of December 31, 2003, for total, domestic, and New Zealand, respectively. The weighted average of 2002 year-end prices for total, domestic, and New Zealand were \$3.49, \$4.23, and \$1.48 per Mcf of natural gas, \$29.27, \$29.36, and \$28.80 per barrel of oil, and \$16.54, \$17.30, and \$12.24 per barrel of NGL, respectively.

[2]At December 31, 2004, 56% of our reserves were proved developed, compared to 59% at December 31, 2003, 60% at December 31, 2002, and 50% at December 31, 2001.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows:

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Future gross revenues	$ 4,711,060,300	$ 4,122,705,861	$ 588,354,439
Future production costs	(1,029,449,670)	(819,035,166)	(210,414,504)
Future development costs	(480,093,684)	(434,305,537)	(45,788,147)
Future net cash flows before income taxes	3,201,516,946	2,869,365,158	332,151,788
Future income taxes	(896,135,438)	(866,598,544)	(29,536,894)
Future net cash flows after income taxes	2,305,381,508	2,002,766,614	302,614,894
Discount at 10% per annum	(840,436,013)	(746,227,690)	(94,208,323)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,464,945,495	$ 1,256,538,924	$ 208,406,571

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Future gross revenues	$ 3,805,349,886	$ 3,279,884,680	$ 525,465,206
Future production costs	(831,430,479)	(678,983,441)	(152,447,038)
Future development costs	(331,816,723)	(301,874,087)	(29,942,636)
Future net cash flows before income taxes	2,642,102,684	2,299,027,152	343,075,532
Future income taxes	(729,624,048)	(657,354,849)	(72,269,199)
Future net cash flows after income taxes	1,912,478,636	1,641,672,303	270,806,333
Discount at 10% per annum	(777,622,101)	(678,769,827)	(98,852,274)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,134,856,535	$ 962,902,476	$ 171,954,059

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Future gross revenues	$ 2,990,669,570	$ 2,578,435,576	$ 412,233,994
Future production costs	(720,599,745)	(612,094,088)	(108,505,657)
Future development costs	(224,792,520)	(208,492,520)	(16,300,000)
Future net cash flows before income taxes	2,045,277,305	1,757,848,968	287,428,337
Future income taxes	(599,195,484)	(512,966,321)	(86,229,163)
Future net cash flows after income taxes	1,446,081,821	1,244,882,647	201,199,174
Discount at 10% per annum	(609,212,030)	(540,375,347)	(68,836,683)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 836,869,791	$ 704,507,300	$ 132,362,491

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues of proved reserves are priced on the basis of year-end prices, except in those instances where fixed and determinable gas price escalations are covered by contracts limited to the price we reasonably expect to receive.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as asset retirement obligation costs, net of salvage value, based on year-end cost estimates and the estimated effect of future income taxes.

4. Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future oil and gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and gas prices for each period. Our hedges at year-end 2004 consisted mainly of crude oil and natural gas price floors with strike prices lower than the period end price and thus did not materially affect prices used in these calculations. Subsequent changes to such year-end oil and gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the consolidated financial statements). Application of these rules during periods of relatively low oil and gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of our oil and gas property reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment, and the risks inherent in reserves estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2004	2003	2002
Beginning balance	$1,134,856,535	$ 836,869,791	$ 454,557,905
Revisions to reserves proved in prior years—			
Net changes in prices and production costs	398,333,372	218,104,882	418,531,747
Net changes in future development costs	(117,672,270)	(108,603,152)	(44,641,133)
Net changes due to revisions in quantity estimates	(12,754,357)	48,194,999	2,582,633
Accretion of discount	152,715,946	116,136,717	60,298,619
Other	49,111,385	(57,822,716)	(88,675,455)
Total revisions	469,734,076	216,010,730	348,096,411
New field discoveries and extensions, net of future production and development costs	30,609,517	243,183,114	190,461,371
Purchases of minerals in place	118,575,886	1,019,290	76,538,437
Sales of minerals in place	(7,339,601)	(13,660,012)	(5,769,642)
Sales of oil and gas produced, net of production costs	(239,669,623)	(158,165,836)	(99,698,403)
Previously estimated development costs incurred	98,924,021	77,404,994	48,752,814
Net change in income taxes	(140,745,316)	(67,805,536)	(176,069,102)
Net change in standardized measure of discounted future net cash flows	330,088,960	297,986,744	382,311,886
Ending balance	$1,464,945,495	$1,134,856,535	$ 836,869,791

Quarterly Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2003 and 2004:

	Revenues	Income Before Income Taxes and Change in Accounting Principle	Income Before Change in Accounting Principle	Net Income	Basic EPS Income Before Change in Accounting Principle	Diluted EPS Income Before Change in Accounting Principle	Basic EPS Net Income	Diluted EPS Net Income
2003:								
First	$ 53,499,993	$ 16,223,744	$ 10,484,937	$ 6,108,085	$ 0.38	$ 0.38	$ 0.22	$ 0.22
Second	50,717,529	11,073,804	7,221,426	7,221,426	0.26	0.26	0.26	0.26
Third	51,552,522	11,153,368	7,062,625	7,062,625	0.26	0.26	0.26	0.26
Fourth	53,130,939	12,288,262	9,501,676	9,501,676	0.35	0.34	0.35	0.34
Total	$ 208,900,983	$ 50,739,178	$ 34,270,664	$ 29,893,812	$ 1.25	$ 1.24	$ 1.09	$ 1.08
2004:								
First	$ 65,355,730	$ 20,086,182	$ 14,587,854	$ 14,587,854	$ 0.53	$ 0.52	$ 0.53	$ 0.52
Second	71,043,735	20,001,147	12,897,927	12,897,927	0.46	0.46	0.46	0.46
Third	74,942,751	19,472,596	14,130,717	14,130,717	0.51	0.50	0.51	0.50
Fourth	98,934,558	41,880,317	26,834,419	26,834,419	0.96	0.93	0.96	0.93
Total	$ 310,276,774	$ 101,440,242	$ 68,450,917	$ 68,450,917	$ 2.46	$ 2.41	$ 2.46	$ 2.41

There were no extraordinary items in 2003 or 2004. As described in Note 4 to the consolidated financial statements, in 2004 we incurred debt retirement costs relating to the repurchase of our 10-1/4% senior subordinated notes due 2009 totaling $9.5 million. Debt retirement costs totaled $2.7 million, $6.8 million and less than $0.1 million in the second, third and fourth quarters of 2004, respectively.

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted net income per common share because to do so would have been antidilutive.

Form 10-K Excerpts

PART I

Items 1 and 2. Business and Properties

See pages 71 and 72 for explanations of abbreviations and terms used herein.

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and gas properties, with a focus on oil and natural gas reserves onshore and in the inland waters of Louisiana and Texas and onshore in New Zealand. We were founded in 1979 and are headquartered in Houston, Texas. At year-end 2004, we had estimated proved reserves of 799.8 Bcfe with a PV-10 Value of $2.0 billion. Our proved reserves at year-end 2004 were comprised of approximately 49% crude oil, 40% natural gas, and 11% NGLs, of which 56% were proved developed. Our proved reserves are concentrated 46% in Louisiana, 33% in Texas, and 18% in New Zealand.

We currently focus primarily on development and exploration in four domestic core areas and two core areas in New Zealand:

- AWP Olmos — South Texas
- Brookeland — East Texas
- Lake Washington — South Louisiana
- Masters Creek — Central Louisiana
- Rimu/Kauri — New Zealand
- TAWN — New Zealand

Competitive Strengths and Business Strategy

Our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to achieve our goals. Our primary goals for the next five years are to increase proved oil and natural gas reserves at an average rate of 5% to 10% per year and to increase production at an average rate of 7% to 12% per year.

Demonstrated Ability to Grow Reserves and Production

We have grown our proved reserves from 454.8 Bcfe to 799.8 Bcfe over the five-year period ended December 31, 2004. Over the same period, our annual production has grown from 42.9 Bcfe to 58.3 Bcfe and our annual net cash provided by operations has increased from $73.6 million to $182.6 million. Our growth in reserves and production over this five year period has resulted primarily from drilling activities in our six core areas combined with producing property acquisitions. More recently, we increased our production by 10% during 2004 as compared to 2003 production. During 2004, our proved reserves decreased by 3%, which replaced 65% of our 2004 production, primarily due to a slowdown in drilling activity in Lake Washington in order to allow for the implementation of a three-dimensional seismic survey and facilities improvements in the area. Also, we focused our drilling efforts in 2004 mainly on development wells, which converted proved undeveloped reserves to proved developed, but did not increase our overall proved reserves. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to grow our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions. In general, we focus on drilling in our core property and emerging growth areas when oil and natural gas prices are strong. When prices weaken and the per unit cost of acquisitions becomes more attractive, or a strategic opportunity exists, we shift our focus toward acquisitions. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. Over the five-year period ended December 31, 2004, we replaced 239% of our production at an average cost of $1.47 per Mcfe. For 2005, we are targeting total production and proved reserves to increase 7% to 12% over the 2004 levels.

Our 2005 capital expenditures are currently budgeted at $200 million to $220 million, net of approximately $5 million to $15 million of non-core property dispositions. Approximately 80% of the budget is targeted for domestic activities, primarily in South Louisiana for Lake Washington and the surrounding area, with about 20% planned for activities in New Zealand. Approximately $15 million to $20 million will be focused on activities at our new properties in the Bay de Chene and Cote Blanche Island fields in South Louisiana that were acquired in December 2004. No acquisitions are currently included in our 2005 capital budget. We expect our 2005 capital expenditures will initially be at the low end of the range, and depending on commodity prices and operational performance, they may increase to the high end of the range during the course of the year. We anticipate 2005 capital expenditures to approximate our cash flow provided from operating activities during 2005.

Reserve Replacement Ratio and Reserve Replacement Cost

Historically we have added proved reserves due to both our drilling and acquisition activities. We believe that this strategy will continue to add reserves for us, however, external factors beyond our control, such as governmental regulations and commodity market factors, could limit our ability to drill wells and acquire proved properties in the future. We calculate and analyze reserve replacement ratios and costs to use as benchmarks against our competitors. These ratios and costs are limited in use by the inherent uncertainties in the reserve estimation process, and other factors discussed below. We have included a table listing the vintages of our proved undeveloped reserves in the table titled "Proved Undeveloped Reserves," and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and gas production. Our reserve additions for each year are estimates. Reserve volumes can change over time and, therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact our ability to access these reserves, such as availability of capital, new and existing government regulations, competition within our industry, the requirement of new or upgraded infrastructure at the production site, and technological advances.

The reserve replacement ratio is calculated using reserve replacement volumes divided by production volumes during a specific period. The reserve replacement volumes used in this calculation are listed in the "Supplemental Information (Unaudited)" section of this report, specifically in a table titled "Supplemental Reserve Information." Within this table there are categories titled "Revisions of previous estimates," "Purchases of minerals in place" and "Extensions, discoveries, and other additions," which when added total the reserve replacement volumes. Production volumes are also listed in the same table, and these production volumes are also used in the reserve replacement ratio calculation.

The reserve replacement cost is calculated using reserve replacement volumes divided by acquisition, exploration and development costs incurred during a specific period. Our acquisition, exploration, and development costs are listed in the "Supplemental Information (Unaudited)" section of this report, specifically in a table titled "Costs Incurred." Development costs as defined by Securities and Exchange Commission rules, include costs incurred to obtain access to proved reserves and provide facilities for extracting, treating, gathering and storing the oil and gas. Development costs thus include well costs for our development wells and facility costs, such as those facility and platform costs we have incurred in our Lake Washington area over the past several years. Costs incurred to explore and develop reserves may extend over several years. We believe a reserve replacement cost estimate is more meaningful when calculated over several periods. Future development costs from prior years are included in this calculation to the extent that they have been included, in our actual costs incurred.

Concentrated Focus on Core Areas with Operational Control

The concentration of our operations in six core areas allows us to realize economies of scale in drilling and production by enabling us to manage larger producing fields with less personnel while minimizing incremental costs of increased drilling and completions. Our average lease operating costs, excluding taxes, were $0.71, $0.64, and $0.58 per Mcfe in 2004, 2003, and 2002, respectively. This concentration allows us to utilize the experience and knowledge we gain in these areas to continually improve our operations and guide us in developing our future activities and in operating similar type assets. For example, we will apply the experience we have gained in Lake Washington to our recently acquired Bay de Chene and Cote Blanche Island properties, which are also situated around South Louisiana salt domes. The value of this concentration is enhanced by our operating 97% of our proved oil and natural gas reserve base as of December 31, 2004. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital and time field development.

Develop Under-Exploited Properties

We are focused on applying modern technologies and recovery methods to areas with known hydrocarbon resources to optimize our exploration and exploitation of such properties. For example, the Lake Washington field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily net production from less than 700 BOE to 12,900 BOE for the quarter ended December 31, 2004. We have also increased our proved reserves in the area from 7.7 million BOE, or 46.2 Bcfe, to approximately 45.4 million BOE or 272.5 Bcfe, as of December 31, 2004. Additionally, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest. We have drilled 32 wells in New Zealand since 1999. When we first acquired our interests in AWP Olmos, Brookeland, and Masters Creek, these areas also had significant additional development potential. Our properties in the Bay de Chene and Cote Blanche Island fields hold mainly proved undeveloped reserves and we intend to begin our initial development activities of these properties in the second half of 2005. We intend to continue acquiring large acreage positions in under-explored and under-exploited areas, where we can apply modern technologies and our experience and knowledge in the areas to grow production from developed fields.

Capitalize on the Near Term Depletion of New Zealand's Largest Gas Field

The Maui field in New Zealand currently supplies over 70% of the natural gas produced in New Zealand. The Maui field is expected to be depleted by 2007, which has caused significant upward pressure on prices for natural gas in the country. Due to currency exchange increases between the New Zealand Dollar and the U.S. Dollar, along with increases in our natural gas contract prices, our average natural gas price in New Zealand has increased 77% from the first quarter of 2003 to the fourth quarter of 2004. We expect the prices we receive for our natural gas in New Zealand to continue to remain strong in the foreseeable future. During 2005, we anticipate drilling seven to ten development wells and expect to drill three to five exploration tests, which includes our Tarata Thrust exploration activity. These New Zealand activities provide us with long-term growth opportunities and significant potential reserves in a country with stable political and economic conditions, existing oil and gas infrastructure, and favorable tax and royalty regimes.

Maintain Financial Flexibility and Disciplined Capital Structure

We practice a disciplined approach to financial management and have historically maintained a disciplined capital structure to provide us with the ability to execute our business plan. As of December 31, 2004, our debt to capitalization was approximately 43%, debt per proved reserves was $0.45 per Mcfe, and our debt to PV-10 ratio was 18%. We plan to maintain a capital structure that provides financial flexibility through the prudent use of capital, aligning our capital expenditures to our cash flows, and an active hedging program. The combination of hedging with collars, floors, forward sales, and the sale of our New Zealand natural gas production under long-term, fixed-price contracts will provide for a more stable cash flow for the limited periods covered as described in the "Commodity Risk" section of this report.

Experienced Technical Team

We employ 42 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 25 years of experience in their technical fields and have been employed by us for an average of over eight years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We have increasingly used seismic technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, post-stack image enhancement reprocessing, amplitude versus offset datasets, correlation cubes, and detailed formation depletion studies. In 2004, we completed our three dimensional seismic survey covering our Lake Washington area and at least four of our 2005 wells in this area will be exploration wells with targets derived from this three-dimensional seismic data.

We use various recovery techniques, including gas lift, water flooding, and acid treatments to enhance crude oil and natural gas production. We also fracture reservoir rock through the injection of high-pressure fluid, install gravel packs, and insert coiled-tubing velocity strings to enhance and maintain production. We believe that the application of fracturing and coiled-tubing technology has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos area.

When appropriate, we develop new applications for existing technology. For example, in New Zealand we acquired seismic data by effectively combining marine seismic data with land seismic data, an application we have not seen any other company use in New Zealand.

We have developed an expertise in drilling horizontal wells at vertical depths below 10,000 feet, often in a high-pressure environment, involving single or dual lateral legs of several thousand feet. This results in an integrated approach to exploration using multidisciplinary data analysis and interpretation that has helped us identify a number of exploration prospects.

We also employ measurement-while-drilling techniques extensively in our Lake Washington area, which allows us to guide the drill bit during the drilling process. This technology allows Swift Energy to steer the well bore path parallel to the salt face and to intersect multiple targeted sands in a single well bore.

Operating Areas

The following table sets forth information regarding our proved reserves and production in our six core areas:

Area	Location	% of Year-End 2004 Proved Reserves	% of 2004 Production
AWP Olmos	South Texas	24%	15%
Brookeland	East Texas	5%	6%
Lake Washington	South Louisiana	34%	40%
Masters Creek	Central Louisiana	7%	6%
Rimu/Kauri	New Zealand	14%	9%
TAWN	New Zealand	5%	19%
% of Total		89%	95%

Domestic Core Operating Areas

AWP Olmos Area. As of December 31, 2004, we owned 27,534 net acres in the AWP Olmos Area in South Texas. We have extensive experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 69% natural gas. At year-end 2004, we owned interests in and operated 512 wells in this area producing natural gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all our operated wells.

In 2004, we completed 13 development wells in this area, and performed four fracture enhancements. At year-end 2004, we had 112 proved undeveloped locations. Our planned 2005 capital expenditures in this area will focus on drilling 12 to 15 wells in this area.

Brookeland Area. As of December 31, 2004, we owned drilling and production rights in 79,040 net acres and 3,500 fee mineral acres in the Brookeland area, which contains substantial proved undeveloped reserves. This area is located in East Texas near the border of Louisiana in Jasper and Newton counties. We primarily drill horizontal wells and produce from the Austin Chalk formation. The reserves are approximately 56% oil and natural gas liquids. At year-end 2004, we had 11 proved undeveloped locations. Our planned 2005 capital expenditures in this area include drilling one to two development wells.

Lake Washington Area. As of December 31, 2004, we owned drilling and production rights in 15,199 net acres in the Lake Washington area located in Plaquemines Parish in South Louisiana, along with lease and seismic options covering another 6,645 acres. Approximately 92% of our proved reserves of 45.4 million BOE in this area at December 31, 2004 were oil and NGLs. To date, we have primarily produced from multiple Miocene sands ranging in depth from greater than 1,700 feet to less than 9,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its inception in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 109 producing wells is gathered from three platforms located in water depths from two to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2004, we drilled 23 development wells and seven exploratory wells, of which 19 development and two exploratory wells were completed. At year-end 2004, we had 85 proved undeveloped locations in this field. Our planned 2005 capital expenditures in this area will focus on drilling at least 30 wells, of these at least four will be exploratory wells with targets derived from recently acquired three-dimensional data. Additional facility work is planned to further improve the deliverability and efficiency in this area.

Masters Creek Area. As of December 31, 2004, we owned drilling and production rights in 48,810 net acres and 91,994 fee mineral acres in the Masters Creek area, which contains substantial proved undeveloped reserves. This area is located in Central Louisiana near the Texas-Louisiana border in the two parishes of Vernon and Rapides. It contains horizontal wells producing both oil and gas from the Austin Chalk formation. The reserves are approximately 68% oil and NGLs. In 2004, we drilled and successfully completed one development well in this area. At year-end 2004, we had nine proved undeveloped locations. Our planned 2005 capital expenditures include drilling one to two development wells.

Domestic Emerging Growth Areas

Garcia Ranch Area. We have been focusing on the deep sands of the Frio formation (10,000 to 16,000 feet) in an area known as Garcia Ranch, which straddles the border of Kenedy County and Willacy County in the southern tip of Texas. Three exploratory wells and one development well were drilled in this area in 2004, of which two exploratory wells were completed.

Bay de Chene and Cote Blanche Island. In December 2004, we acquired approximately 14,200 gross acres in the Bay de Chene field and approximately 6,200 gross acres in the Cote Blanche Island field, both of which are in South Louisiana in close proximity to Lake Washington. Bay de Chene is located in Jefferson Parish and Lafourche Parish, while Cote Blanche Island is located in St. Mary Parish. These fields hold predominantly undeveloped reserves. We plan to spend $15 million to $20 million to begin developing these fields in the later part of 2005. These fields were shut-in following the acquisition for facility enhancements and to repair a gas supply line.

New Zealand Core Operating Areas

Our activity in New Zealand began in 1995. As of December 31, 2004, our exploration permit 38719, which we operate, included approximately 72,769 acres in the Taranaki Basin of New Zealand's north island. In April 2004, two other permits (38756 and 38759) within the Taranaki Basin were consolidated with our permit 38719 to form one permit area. This acreage includes our Rimu/Kauri area, our Rimu mining permit area, and our Tawa prospect.

Rimu/Kauri Area. Since 2002, we have held a 100% working interest in petroleum mining permit 38151 covering approximately 5,500 acres in the Rimu area for a primary term of 30 years. We began commercial production from the Rimu area in May 2002. During 2004, we completed ten of 11 wells in the Kauri area. Five of these wells successfully targeted the Kauri sands, and five were completed in the Manutahi sand. We have applied for a 30-year primary term mining permit covering approximately 8,714 acres in the Kauri area. Our natural gas production from this area is sold to Genesis Power Ltd. under a long-term contract for use at its Huntly Power Station, New Zealand's largest thermal power station.

TAWN Area. Our interest in TAWN consists of a 100% working interest in four petroleum mining permits, 38138 through 38141, covering producing oil and gas fields and extensive associated hydrocarbon-processing facilities and pipelines. The properties are collectively identified as the TAWN properties, an acronym derived from the first letters of the field names — the Tariki field, the Ahuroa field, the Waihapa field, and the Ngaere field. The four fields include 18 wells where the purchaser of gas, Contact Energy, has contracted to take minimum quantities and can call for higher production levels to meet electrical demand in New Zealand. In 2004, we completed the Tariki-D1 well in this area. The TAWN assets are located approximately 17 miles north of the Rimu/Kauri area.

Our infrastructure at TAWN includes two hydrocarbon-processing plants with significant excess capacity. We also own the pipelines connecting the fields and facilities to export terminals and interior markets.

New Zealand Emerging Growth Areas

The Tawa prospect, which is scheduled for drilling in 2005, is located in permit 38719 northwest of the Rimu area. Its main targets are the Kauri, Tariki, and Kapuni sands. Consisting of a combination of structural and stratigraphic traps, this prospect was developed based upon our analysis of existing two and three-dimensional seismic data. The Tawa prospect may also include a shallower prospect located on the southeast flank of the prospect.

Two prospects, also scheduled for drilling in 2005, are located in our TAWN area and are identified as the Goss prospect (Goss A1 well), and the Trapper prospect (Trapper A1 well). Both prospects will have the Kapuni group sands (the major reservoir in the basin) as their main target, but as these wells are drilled they will also pass through the Tariki sandstone and other major producing sands in the basin .We have entered into a series of farm-out agreements with Mighty River Power ("MRP"), a state owned New Zealand utility, that provide for a 50% working interest in relation to the Goss A1 well, the Trapper A1 well, and a well on our Tawa prospect. Under the farm-out agreement, MRP will provide the funding for the drilling of the three exploration wells to earn a 50% working interest in any commercial discoveries resulting from these prospects. Once MRP has earned its 50%, we will equally share any future development costs subject to the terms of the agreements. Swift will continue to maintain its 100% working interest in the existing producing horizons and facilities in both the TAWN and Rimu/Kauri areas.

Swift also holds a 71% interest in exploration permit 38718, covering approximately 28,600 gross acres northeast of our TAWN area, and a 21% interest in exploration permit 38716, covering approximately 33,000 gross acres southeast of our TAWN area. In December 2004, we entered into a farm-in agreement with Ballance Agri-Nutrients Limited of New Zealand for 60% of their exploration permit 38742. The approximately 16,800 gross acre permit is located onshore in the north-central Taranaki Basin. Under the terms of the contract we became the operator of the permit and anticipate drilling an exploratory well in this area in the second half of 2005.

Summary of New Zealand Government Leases

Our acreage in New Zealand is licensed from the New Zealand government under production exploration permits (PEP), production mining licenses (PML), and production mining permits (PMP). These licenses and permits are summarized in the following table:

Permit	Date Swift Acquired/Granted Initial Interest	Swift's Interest
PEP 38716	1999	21%
PEP 38718	2000	71%
PEP 38719	1996	100%
PEP 38742	2004	60%
PML 38138	2002	100%
PML 38139	2002	100%
PML 38140	2002	100%
PML 38141	2002	100%
PMP 38151	2002	100%

The New Zealand government's Crown Minerals website has details of these licenses at http://crownminerals.med.govt.nz/index.asp.

Oil and Natural Gas Reserves

The following tables present information regarding proved reserves of oil and natural gas attributable to our interests in producing properties as of December 31, 2004, 2003, and 2002. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us and audited by H. J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers. Gruy has audited 100% of our proved reserves. Gruy's audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum

Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of all available production histories and other geological, economic, and engineering data, all of which was provided by us.

Estimates of future net revenues from our proved reserves and the PV-10 Value are made using oil and gas sales prices in effect as of the dates of such estimates adjusted for the effects of hedging and are held constant, for that year's reserve calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. Our hedges at year-end 2004 consisted mainly of crude oil and natural gas price floors with strike prices lower than the period-end price and thus did not materially affect prices used in these calculations. The weighted averages of such year-end 2004 prices domestically were $5.87 per Mcf of natural gas, $42.21 per barrel of oil, and $26.49 per barrel of NGL, compared to $5.53, $30.88, and $21.81 at year-end 2003 and $4.23, $29.36, and $17.30 at year-end 2002, respectively. The weighted averages of such year-end 2004 prices for New Zealand were $3.07 per Mcf of natural gas, $33.60 per barrel of oil, and $20.48 per barrel of NGL, compared to $2.04, $26.78, and $14.10 in 2003 and $1.48, $28.80, and $12.24 in 2002, respectively. The weighted averages of such year-end 2004 prices for all our reserves, both domestically and in New Zealand, were $5.16 per Mcf of natural gas, $41.07 per barrel of oil, and $25.48 per barrel of NGL, compared to $4.56, $30.16, and $20.61 in 2003 and $3.49, $29.27, and $16.54 in 2002, respectively. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the SEC and its PV-10 Value as of December 31, 2004, 2003, and 2002. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. We combine NGLs with oil for reserve reporting purposes.

Estimated Proved Oil and Natural Gas Reserves	Year Ended December 31, 2004 Total	Domestic	New Zealand
Natural gas reserves (MMcf):			
Proved developed	193,311	140,549	52,762
Proved undeveloped	124,935	97,343	27,593
Total	318,246	237,892	80,355
Oil reserves (MBbl):			
Proved developed	42,038	36,629	5,409
Proved undeveloped	38,229	32,510	5,719
Total	80,267	69,139	11,128
Estimated Present Value of Proved Reserves (in thousands)			
Proved developed	$ 1,181,748	$ 1,037,617	$ 144,130
Proved undeveloped	839,127	759,724	79,403
PV-10 Value	$ 2,020,875	$ 1,797,341	$ 223,533

Estimated Proved Oil and Natural Gas Reserves	Year Ended December 31, 2003 Total	Domestic	New Zealand
Natural gas reserves (MMcf):			
Proved developed	210,120	138,173	71,947
Proved undeveloped	125,685	104,148	21,537
Total	335,805	242,321	93,484
Oil reserves (MBbl):			
Proved developed	45,525	38,768	6,757
Proved undeveloped	35,235	28,248	6,987
Total	80,760	67,016	13,744
Estimated Present Value of Proved Reserves (in thousands)			
Proved developed	$ 940,883	$ 805,834	$ 135,049
Proved undeveloped	597,912	517,485	80,427
PV-10 Value	$ 1,538,795	$ 1,323,319	$ 215,476

Estimated Proved Oil and Natural Gas Reserves	Year Ended December 31, 2002 Total	Domestic	New Zealand
Natural gas reserves (MMcf):			
Proved developed	233,515	149,732	83,783
Proved undeveloped	93,217	90,092	3,125
Total	326,732	239,824	86,908
Oil reserves (MBbl):			
Proved developed	35,928	26,530	9,398
Proved undeveloped	34,511	32,500	2,011
Total	70,439	59,030	11,409
Estimated Present Value of Proved Reserves (in thousands)			
Proved developed	$ 679,356	$ 516,833	$ 162,523
Proved undeveloped	481,833	456,632	25,201
PV-10 Value	$ 1,161,189	$ 973,465	$ 187,724

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Future prices received for the sale of oil and gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and gas reserves.

No other reports on our reserves have been required to be filed, nor have any been filed with any federal agency.

Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our proved undeveloped reserves as of December 31, 2004:

Year Added	Volume (Bcfe)	% of PUD Volumes	PV-10 Value (in millions)	% of PUD PV-10 Value
2004	111.5	31%	$ 367.5	44%
2003	80.0	23%	205.2	24%
2002	30.6	9%	61.7	7%
2001	17.7	5%	40.1	5%
2000	43.4	12%	54.8	7%
Prior to 2000	71.0	20%	109.1	13%
Total	354.2	100%	$ 838.4	100%

Sensitivity of Reserves to Pricing

As of December 31, 2004, a 5% increase in crude oil and NGL pricing would increase our total estimated proved reserves of 799.8 Bcfe by approximately 0.6 Bcfe, and increase the total PV-10 value of $2.0 billion by approximately $89 million. Similarly, a 5% decrease in crude oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.7 Bcfe and decrease the total PV-10 value by approximately $89 million.

As of December 31, 2004, a 5% increase in natural gas pricing (exclusive of fixed contract volumes) would increase our total estimated proved reserves by approximately 0.6 Bcfe and increase the total PV-10 value by approximately $33 million. Similarly, a 5% decrease in natural gas pricing (exclusive of fixed contract volumes) would decrease our total estimated proved reserves by approximately 0.6 Bcfe and decrease the total PV-10 value by approximately $34 million.

Oil and Gas Wells

The following table sets forth the gross and net wells in which we owned an interest at the following dates:

	Oil Wells	Gas Wells	Total Wells[1]
December 31, 2004:			
Gross	358	574	932
Net	308.8	525.9	834.7
December 31, 2003:			
Gross	397	560	957
Net	340.6	504.0	844.6
December 31, 2002:			
Gross	342	555	897
Net	278.9	479.8	758.7

[1]Excludes 40 service wells in 2004, 41 service wells in 2003, and 35 service wells in 2002.

Oil and Gas Acreage

As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights. In many instances, title opinions may not be obtained if in our judgment it would be uneconomical or impractical to do so.

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2004:

	Developed[1]		Undeveloped[1]	
	Gross	Net	Gross	Net
Alabama	9,046.11	2,588.73	124.22	79.82
Louisiana	100,464.00	82,814.43	16,342.11	11,481.30
Texas	151,824.86	103,029.72	17,765.95	9,396.36
Wyoming	681.07	151.06	66,015.91	64,252.13
All other states	320.00	266.66	400.00	257.32
Offshore Louisiana	4,609.37	276.56	5,000.00	258.34
Offshore Texas	2,880.00	74.39	—	—
Total Domestic	269,825.41	189,201.55	105,648.19	85,725.27
New Zealand	8,240.00	7,865.60	173,043.90	132,578.17
Total	278,065.41	197,067.15	278,692.09	218,303.44

[1]Fee mineral acres acquired in the Brookeland and Masters Creek areas acquisition are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 69,149 undeveloped fee mineral acres for a total of 95,494 fee mineral acres.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2004:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2004	Exploratory–Domestic	10	4	6	7.5	2.3	5.2
	Development–Domestic	44	37	7	41.7	35.0	6.7
	Exploratory–New Zealand	1	—	1	1.0	—	1.0
	Development–New Zealand	11	10	1	11.0	10.0	1.0
2003	Exploratory–Domestic	8	5	3	7.3	5.0	2.3
	Development–Domestic	63	53	10	61.9	51.9	10.0
	Exploratory–New Zealand	1	—	1	0.5	—	0.5
	Development–New Zealand	3	3	—	3.0	3.0	—
2002	Exploratory–Domestic	7	3	4	5.0	2.3	2.7
	Development–Domestic	23	17	6	23.0	17.0	6.0
	Exploratory–New Zealand	3	2	1	2.2	2.0	0.2
	Development–New Zealand	3	2	1	3.0	2.0	1.0

Operations

We generally seek to be operator in the wells in which we have a significant economic interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors supervised by us provide all the equipment and personnel. We employ drilling, production, and reservoir engineers, geologists, and other specialists who work to improve production rates, increase reserves, and lower the cost of operating our oil and gas properties.

Oil and gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator's direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2004 totaled $5.8 million and ranged from $600 to $2,155 per well per month.

Marketing of Production

Domestically, we typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We typically sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. Shell, both domestically and in New Zealand accounted for 10% or more of our total revenues during the year ended December 31, 2004, with purchases accounting for approximately 48% of total oil and gas sales. For the year-ended December 31, 2003, Shell, both domestically and in New Zealand, and Contact Energy in New Zealand together accounted for approximately 26% of our total oil and gas sales. However, due to the availability of other purchasers, we do not believe that the loss of any single oil or gas purchaser or contract would materially affect our revenues.

In 1998, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP Olmos area with PG&E Energy Trading Corporation, which was assumed in December 2000 by El Paso Hydrocarbon, LP, and El Paso Industrial, LP, and then assumed by Enterprise Hydrocarbons L.P. in September 2004, for up to 75,000 Mcf per day, which provided for a ten-year term with automatic one-year extensions unless earlier terminated. We believe that these arrangements adequately provide for our gas transportation and processing needs in the AWP Olmos area for the foreseeable future.

Our oil production from the Brookeland and Masters Creek areas is sold to various purchasers at prevailing market prices. Our natural gas production from these areas is processed under long term gas processing contracts with Duke Energy Field Services, Inc. The processed liquids and residue gas production are sold in the spot market at prevailing prices.

Our oil production from the Lake Washington area is delivered into ExxonMobil's crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices or at fixed prices tied to the then current Nymex crude oil contract for the applicable month(s) Our natural gas production from this area is either consumed on the lease or is delivered into El Paso's Tennessee Gas Pipeline system and then sold in the spot market at prevailing prices.

Our oil production in New Zealand is sold to Shell Petroleum Mining at international prices tied to the Asia Petroleum Price Index (APPI) Tapis posting, less the cost of storage, trucking, and transportation.

Our natural gas production from our TAWN fields is sold under a long-term fixed price contract with Contact Energy. Our natural gas production from the Rimu field is sold to Genesis Power Ltd. under a long-term fixed price contract that was modified in 2003 and covers approximately 7.2 Bcfe per year for a three-year period. During 2004, additional production volumes from our fields, over the contract maximum, were sold to Contact Energy or Genesis Power Ltd. at prevailing market rates.

Production of NGLs in New Zealand is sold to Rockgas Ltd. under long-term contracts tied to New Zealand's domestic natural gas liquids market.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and natural gas production for the three-year period ended December 31, 2004:

	Year Ended December 31,		
	2004	2003	2002
Net Sales Volume:			
Oil (MBbls)[1]	4,722	3,369	2,597
Natural Gas Liquids (MBbls)[2]	1,040	823	1,174
Natural Gas (MMcf)[3]	23,742	28,003	27,132
Total (MMcfe)	58,319	53,158	49,752
Average Sales Price:			
Oil (per Bbl)[1]	$ 40.24	$ 29.89	$ 24.52
Natural Gas Liquids (per Bbl)[2]	$ 22.52	$ 17.60	$ 12.82
Natural Gas (per Mcf)[3]	$ 4.12	$ 3.42	$ 2.30
Average Production Cost (per Mcfe)	$ 1.23	$ 0.99	$ 0.83

[1]Oil production for 2004, 2003, and 2002 includes New Zealand production of 452,753 barrels at an average price per barrel of $42.15, 572,683 barrels at an average price per barrel of $29.58, and 483,591 barrels at an average price per barrel of $24.31, respectively.

[2]Natural gas liquids production for 2004, 2003 and 2002 includes New Zealand production of 350,303 barrels at an average price of $17.96 per barrel, 283,227 barrels with an average price of $13.50 per barrel, and 211,864 barrels with an average price of $11.06 per barrel.

[3]Natural gas production for 2004, 2003 and 2002 includes New Zealand production of 11,441,954 Mcf with an average price of $2.38 per Mcf, 14,258,679 Mcf with an average price of $1.83 per Mcf, and 11,351,518 Mcf with an average price of $1.32 per Mcf.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, pipe failure, casing collapse, and fires, each of which could result in severe damage to or destruction of oil and gas wells, production facilities or other property, or individual injuries. The oil and gas exploration business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. We maintain comprehensive insurance coverage, including general liability insurance in an amount not less than $50 million. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident, or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. At December 31, 2004, we had in place price floors in effect through the December 2005 contract month for natural gas; these cover a portion of our domestic natural gas production for January 2005 to December 2005. The natural gas price floors cover notional volumes of 4,000,000 MMBtu, with a weighted average floor price of $5.83 per MMBtu. Our natural gas price floors in place at December 31, 2004 are expected to cover approximately 30% to 35% of our domestic natural gas production from January 2005 to December 2005. At December 31, 2004, we also had in place price crude oil price floors in effect through the March 2005 contract month, which cover a portion of our domestic crude oil production for January 2005 to March 2005. The crude oil price floors cover notional volumes of 216,000 barrels, with a weighted average floor price of $37.00 per barrel. Our crude oil price floors in place at December 31, 2004 are expected to cover approximately 15% to 20% of our domestic crude oil production from January 2005 to March 2005.

Employees

At December 31, 2004, we employed 272 persons. Of these employees, 69 were in New Zealand, including four expatriate employees. Eight of our New Zealand employees are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, changes in and stock ownership of our directors and executive officers, together with other documents filed with the Securities and Exchange Commission under the Securities Exchange Act can be accessed free of charge on our web site at www.swiftenergy.com as soon as reasonably practicable after we electronically file these reports with the SEC. All exhibits and supplemental schedules to these reports are available free of charge through the SEC web site at www.sec.gov. In addition, we have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. We have posted this Code of Ethics on our web site, where we also intend to post any waivers from or amendments to this Code of Ethics.

Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

Bbl — Barrel or barrels of oil.

Bcf — Billion cubic feet of natural gas.

Bcfe — Billion cubic feet of natural gas equivalent (see Mcfe).

BOE — Barrels of oil equivalent.

Development Well — A well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

Discovery Cost — With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred exploration and development costs (exclusive of future development costs) by net reserves added during the period through extensions, discoveries, and other additions.

Dry Well — An exploratory or development well that is not a producing well.

EBITDA — Earnings before interest, taxes, depreciation, depletion and amortization.

EBITDAX — Earnings before interest, taxes, depreciation, depletion and amortization, and exploration expenses. Since Swift uses full-cost accounting for oil and property expenditures, as noted in footnote one of the accompanying consolidated financial statements, exploration expenses are not applicable to Swift.

Exploratory Well — A well drilled either in search of a new, as yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir.

FASB — The Financial Accounting Standards Board.

Gigajoules — A unit of energy equivalent to .95 Mcf of 1,000 Btu of natural gas.

Gross Acre — An acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

Gross Well — A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

MBbl — Thousand barrels of oil.

Mcf — Thousand cubic feet of natural gas.

Mcfe — Thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate, or natural gas liquids to 6 Mcf of natural gas.

MMBbl — Million barrels of oil.

MMBtu — Million British thermal units, which is a heating equivalent measure for natural gas and is an alternate measure of natural gas reserves, as opposed to Mcf, which is strictly a measure of natural gas volumes. Typically, prices quoted for natural gas are designated as price per MMBtu, the same basis on which natural gas is contracted for sale.

MMcf — Million cubic feet of natural gas.

MMcfe — Million cubic feet of natural gas equivalent (see Mcfe).

Net Acre — A net acre is deemed to exist when the sum of fractional working interests owned in gross acres equals one. The number of net acres is the sum of fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Net Well — A net well is deemed to exist when the sum of fractional working interests owned in gross wells equals one. The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

NGL— Natural gas liquid.

Producing Well — An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Proved Developed Oil and Gas Reserves* — Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Oil and Gas Reserves* — The estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

Proved Undeveloped Oil and Gas Reserves* — Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Proved Undeveloped (PUD) Locations — A location containing proved undeveloped reserves.

PV-10 Value — The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

Reserves Replacement Cost — With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred acquisition, exploration, and development costs (exclusive of future development costs) by net reserves added during the period.

SFAS — Statement of Financial Accounting Standards.

TAWN — New Zealand producing properties acquired by Swift in January 2002. TAWN is comprised of the Tariki, Ahuroa, Waihapa, and Ngaere fields.

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*These definitions regarding various types of proved reserves are only abbreviated versions of the Securities and Exchange Commission's definitions of these terms contained in Rule 4-10(a) of Regulation S-X. See www.sec.gov/divisions/corpfin/forms/regsx.htm#gas for the full text of the SEC's definitions of these terms.

NOTICE

Those portions (other than Items 10-14 incorporated by reference to Swift's proxy statement for its 2005 Annual Meeting of Shareholders) of the Form 10-K Report for the year ended December 31, 2004, not included in this Annual Report to Shareholders (including certain portions of Item 1–Business pertaining to "Competition," "Regulations," "Federal Leases," "Facilities," "Litigation," Item 3–Legal Proceedings, Item 4–Submission of Matters to a Vote of Security Holders, Item 7–Management's Discussion and Analysis of Financial Condition and Results of Operations pertaining to "Other Factors Affecting Our Business and Financial Results," Item 9–Changes in and Disagreements with Accountants on Accounting and Financial Disclosure, Item 9a–Controls and Procedures, Item 14–Principal Accountant Fees and Services, and Item 15–Exhibits, Financial Statement Schedules, and Reports on Form 8-K), with no disclosures having been made as to Item 4, will be provided without charge to shareholders making a written request to Scott Espenshade, Director of Corporate Development and Investor Relations, Swift Energy Company, 16825 Northchase Drive, Suite 400, Houston, Texas 77060. Exhibits filed as part of the Form 10-K will be provided to shareholders making a written request as set forth above at a reasonable charge sufficient to cover the Company's cost in providing such exhibits.

Investor Information

BOARD OF DIRECTORS

A. Earl Swift
Chairman of the Board
Swift Energy Company

Virgil N. Swift
Vice Chairman of the Board
Swift Energy Company
Chairman, Swift Energy International

Terry E. Swift
Chief Executive Officer
Swift Energy Company

Deanna L. Cannon
President
Cannon & Company CPA's PLC

G. Robert Evans
Retired Chairman & CEO
Material Sciences Corporation

Raymond E. Galvin
Retired President
Chevron U.S.A. Production Company

Greg Matiuk
Retired Executive Vice President
Administration & Corporate Services
ChevronTexaco Corporation

Henry C. Montgomery
Chairman & Founder
Montgomery Professional
Services Corporation

Clyde W. Smith, Jr.
President
Ascentron, Inc.

Raymond O. Loen
Director Emeritus

OFFICERS

Terry E. Swift
Chief Executive Officer

Bruce H. Vincent
President & Secretary

Joseph A. D'Amico
Executive Vice President &
Chief Operating Officer

Alton D. Heckaman, Jr.
Executive Vice President &
Chief Financial Officer

James M. Kitterman
Senior Vice President–Operations

James P. Mitchell
Senior Vice President–Commercial
Transactions & Land

Victor R. Moran
Senior Vice President &
Chief Compliance Officer

Gerald B. Long
Vice President–Production Operations

Thomas E. Schmidt
Vice President–Exploitation &
Development

Tara L. Seaman
Vice President–Reserves & Evaluations

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

Laurent A. Baillargeon
General Counsel

CORPORATE HEADQUARTERS

Swift Energy Company
16825 Northchase Drive, Suite 400
Houston, Texas 77060
Telephones: (281) 874-2700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANIES

Swift Energy International, Inc.
Houston, Texas

Swift Energy New Zealand, Ltd.
Wellington, New Zealand

SWENCO-Western, Inc.
Houston, Texas

GASRS, Inc.
Houston, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer
& Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038

EXCHANGE LISTINGS

New York Stock Exchange
Pacific Exchange, Inc.
Symbol "SFY"

INDEPENDENT ACCOUNTANTS

Ernst & Young LLP
1401 McKinney, Suite 1200
Houston, Texas 77010

COUNSEL

Jenkens & Gilchrist
A Professional Corporation
1401 McKinney, Suite 2600
Houston, Texas 77010

Common Stock, 2003 and 2004

Our common stock is traded on the New York Stock Exchange and the Pacific Exchange, Inc., under the symbol "SFY." The high and low quarterly sales prices for our common stock for 2003 and 2004 were as follows:

	2003				2004			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$8.51	$7.60	$10.64	$13.57	$15.90	$18.72	$18.16	$23.50
High	$9.76	$12.14	$14.57	$18.00	$20.02	$22.75	$25.16	$30.34

Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our credit agreements, as discussed in Note 4 to the Consolidated Financial Statements, and we presently intend to continue a policy of using retained earnings for expansion of our business.

We had approximately 298 stockholders of record as of December 31, 2004.

Annual Meeting
4 p.m., Tuesday, May 10, 2005
The Wyndham Greenspoint Hotel
12400 Greenspoint Drive
Houston, Texas 77060

SWIFT ENERGY COMPANY
2004 ANNUAL REPORT

25 years

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Houston, Texas 77060
Phone: (281) 874-2700
Web Site: www.swiftenergy.com
NYSE, PCX: SFY