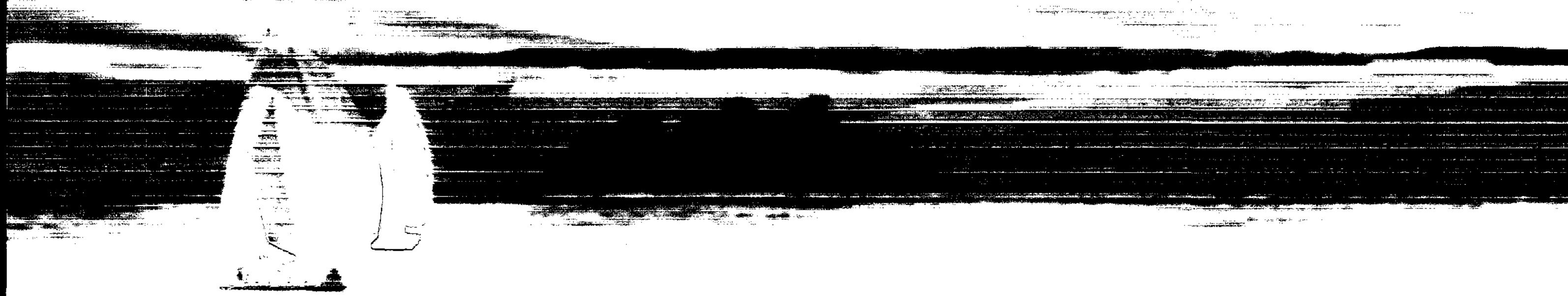
NEW HORIZONS

SWIFT ENERGY COMPANY

2001 ANNUAL REPORT



Swift Energy Highlights	2001	2000	Percent Change
Revenues	$183,807,490	$191,624,946	(4)%
Oil and Gas Sales	$181,184,635	$189,138,947	(4)%
Costs & Expenses (excluding write-down of oil & gas properties)	$119,137,576	$98,545,600	21%
Write-down of Oil & Gas Properties	$98,862,247	—	—
Net Income	$(22,347,765)	$59,184,008	(138)%
Earnings per Share–Basic	$(0.90)	$2.79	(132)%
Earnings per Share–Diluted	$(0.90)	$2.51	(136)%
Total Assets	$671,684,833	$572,387,001	17%
Working Capital	$(36,492,355)	$(22,451,892)	(63)%
Current Ratio	.50	.65	(23)%
Long-Term Debt	$258,197,128	$134,729,485	92%
Stockholders' Equity	$312,652,720	$332,154,155	(6)%
Long-Term Debt to Equity Ratio	.83	.41	102%
Return on Assets (net income / average assets)	(4)%	12%	(133)%
Return on Stockholders' Equity (net income / average equity)	(7)%	24%	(129)%
Net Cash Provided by Operating Activities	$139,884,255	$128,197,227	9%
Weighted Average Shares Outstanding	24,732,099	21,244,684	16%
Year-End Shares Outstanding	24,795,564	24,608,344	1%
Market Price of Common Stock at Year-End	$20.20	$37.63	(46)%
Number of Shareholders of Record	383	477	(20)%
Number of Shareholders in Street Name	7,690	5,616	37%
Natural Gas Production (Mcf)	26,458,958	27,524,621	(4)%
Oil, NGL, & Condensate Production (Bbls)	3,055,373	2,472,014	24%
Total Production (Mcfe)	44,791,202	42,356,705	6%
Average Natural Gas Prices Received ($/Mcf)	$4.23	$4.24	—
Average Oil, NGL, & Condensate Prices Received ($/Bbl)	$22.64	$29.35	(23)%
Average Composite Prices Received ($/Mcfe)	$4.05	$4.47	(9)%
Proved Natural Gas Reserves (Mcf)	324,912,125	418,613,976	(22)%
Proved Oil, NGL, & Condensate Reserves (Bbls)	53,482,636	35,133,596	52%
Total Proved Reserves (Mcfe)	645,807,939	629,415,552	3%
Number of Employees	209	181	15%

See page 29 regarding the forward-looking statements in this report.
See page 59 for a glossary of abbreviations and terms.

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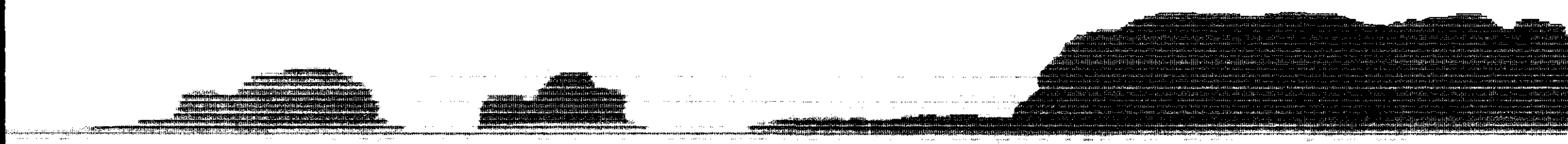

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Internet Access

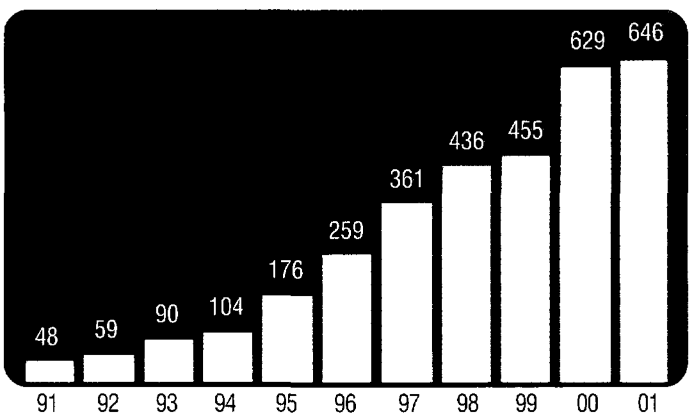
Additional news and information about Swift Energy Company is available on the web at http://www.swiftenergy.com. The site is updated with press releases, quarterly reports, 10-Ks and 10-Qs, and a variety of other information. Visitors to swiftenergy.com can register to receive periodic e-mail updates concerning new information available at the web site.

COMPANY PROFILE

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 on onshore areas of Texas and Louisiana in the United States and onshore areas of the Taranaki Basin in New Zealand.

Mission and Goals. As a natural resource company, Swift Energy's mission has always been to achieve growth in the volume and net present value of its proved reserves. The underlying premise is that reserves growth leads to increases in oil and gas production and sales, which in turn lead to higher cash flows and earnings, and ultimately to increases in shareholder value.

Year-End Proved Reserves
(Bcfe)



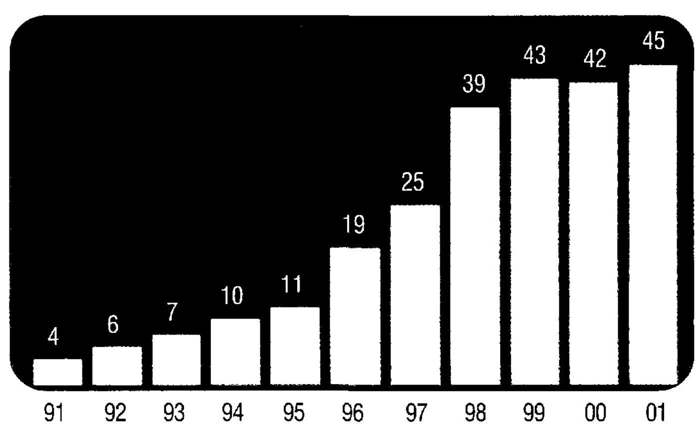
Over the last 10 years, the Company has achieved an average compounded growth rate in proved oil and gas reserves of approximately 30% per year. Swift's success in sustaining reserves growth in a volatile pricing environment has enabled it to achieve 10-year compounded growth rates of approximately 27% per year in production, 36% per year in oil and gas sales, and 37% per year in cash flows from operating activities. Swift's primary goals for the next few years are to continue increasing both its oil and gas reserves and its production at an average rate of 10% to 15% per year.

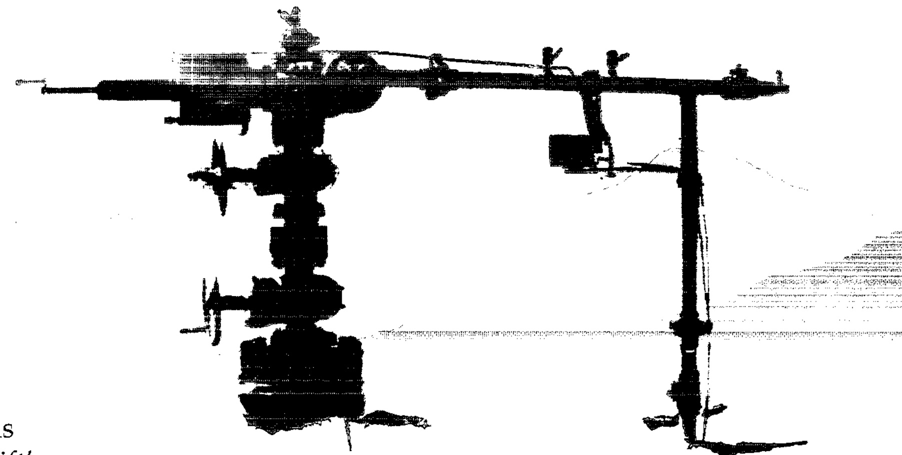
Business Strategy. Swift's reserves growth is primarily accomplished through a mix of exploratory and development drilling and producing property acquisitions. The specific mix of drilling and acquisitions is continually adjusted in response to changing industry conditions. In all its activities, the Company focuses on building a balanced portfolio of oil and gas properties with diversified production profiles and an assortment of drilling opportunities covering a range of risks and potential rewards.

Domestic drilling is generally focused on core operating areas, including the Lake Washington Area and Masters Creek Area in Louisiana and the AWP Olmos Area and Brookeland Area in Texas. In 2002, domestic drilling activities will be concentrated in the Lake Washington Area. International drilling activities will be focused in the Company's Rimu/Kauri Area in New Zealand, where the Company is delineating what it believes to be a major multizone discovery.

In its acquisitions activities, the Company continuously reviews opportunities to purchase strategic producing properties where performance can be enhanced through development drilling or improved operating efficiencies. In 2001, Swift acquired interests in the Lake Washington Area in South Louisiana, and in January 2002, the Company acquired four onshore producing oil and gas fields in New Zealand, collectively known as the TAWN properties, through the purchase of an affiliate of Shell New Zealand.

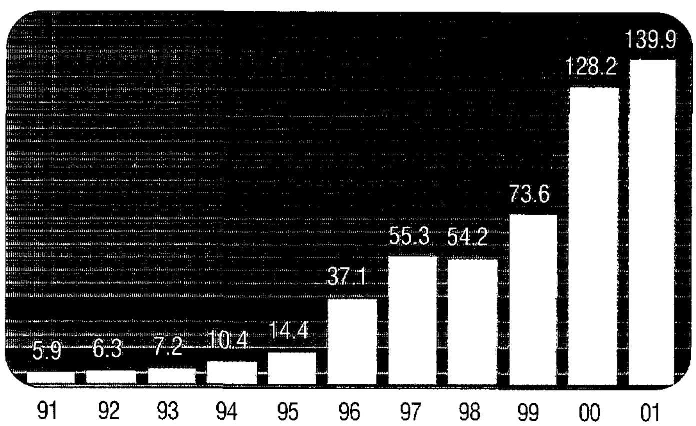
Annual Oil and Gas Production
(Bcfe)





Industry Environment. Because oil, natural gas liquids, and condensate represented over 40% of Swift's total production in 2001, falling oil prices had a major impact on revenues from oil and gas sales. Sharp price declines during the second half of 2001 were a dramatic contrast to strong prices throughout the previous year. For 2001 as a whole, Swift received an average of $22.64 per barrel for its oil, a decrease of 23% over average oil prices received during 2000. Average natural gas prices received by the Company in 2001 totaled $4.23 per thousand cubic feet (Mcf), remaining essentially flat compared to the previous year despite declining sharply from unusual highs early in the year.

Net Cash Provided by Operating Activities
($ Million)

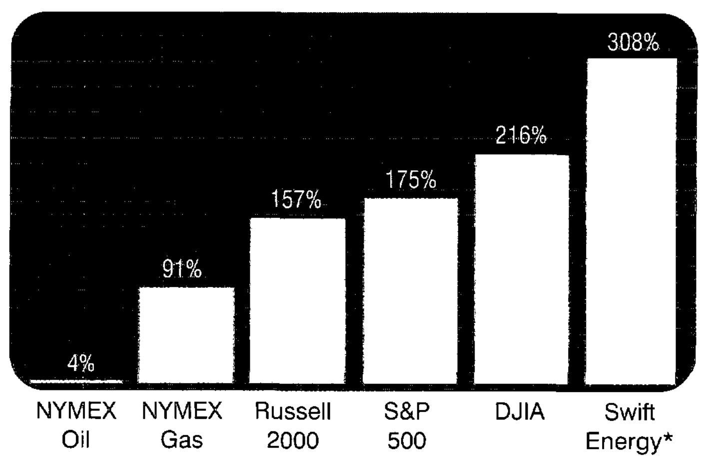


The 2001 composite price received for the Company's production decreased 9% to $4.05 per thousand cubic feet of natural gas equivalent (Mcfe). At the same time, high demand for oilfield services significantly increased the costs associated with drilling and production operations, leading to even greater declines in operating margins.

Prices at the end of 2001 were much lower than average prices for the year as a whole. Year-end proved reserves values used in ceiling test calculations must be based upon pricing at the end of the year. Average year-end oil and natural gas prices used in the ceiling test of Swift's domestic proved reserves were $18.51 per barrel for oil and $2.68 per Mcf for gas. This year-end pricing necessitated a $98.9 million non-cash write-down of the Company's domestic oil and gas assets, leading to a net loss of $(22.3) million for 2001. Ceiling test calculations, which are calculated country by country, did not result in a write-down of the Company's oil and gas assets in New Zealand.

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. From year-end 1991 to year-end 2001, Swift's stock price increased a cumulative 308%, which compares favorably with cumulative increases in the Dow Jones Industrial Average (216%), the S&P 500 index (175%), the Russell 2000 index (157%), NYMEX natural gas prices (91%), and NYMEX oil prices (4%).

10-Year Performance Comparison
(Cumulative Increases from 12/31/1991 to 12/31/2001)



* Swift stock prices are restated in recognition of 1994 and 1997 stock dividends.

Investor Information. Swift Energy's common stock has been traded under the symbol "SFY" on the New York Stock Exchange (NYSE) since 1991 and on the Pacific Exchange, Inc., since 1988.

NEW HORIZONS
Letter to Stockholders

Oil and gas producers often use the word "horizons." We talk about planning horizons and, of course, geological horizons. This year, at Swift Energy, we have also been discussing "new horizons"—not only those unique to our Company, but also those that are new to our industry, and other industries, because of the impact of unprecedented world events. While some of these new horizons may not engender optimism, many are offering unparalleled opportunities. Indeed, we have never seen a better time in our Company's history for building shareholder value.

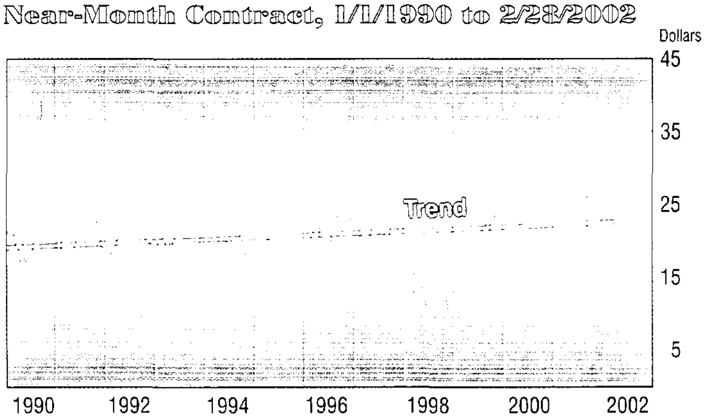
We believe that the year 2001 can be viewed as an aberration, even within a normally cyclical industry. Events largely outside our control converged in 2001 to send us from the best performance in our history during the first quarter of the year to the worst performance during the last quarter. As a result, our increase in oil and gas reserves (3%) and production (6%) were not as large as we had expected.

While our cash flows from operating activities rose 9%, net income for the year was greatly affected by significant non-recurring charges, the largest of which was a $98.9 million ($63.5 million after tax) non-cash write-down of our domestic oil and gas assets triggered by low year-end prices. In addition, the Company recorded a $2.1 million charge that included both delinquent accounts receivable, mainly related to natural gas sold to Enron in November, and a write-off of debt issuance costs for a planned offering that was cancelled due to market conditions after the September 11 tragedy.

With these total non-recurring charges of $101.0 million, we recorded a net loss for the year of $(22.3) million, or $(0.90) per diluted share. Net income excluding these non-recurring charges totaled $42.5 million in 2001, or $1.67 per diluted share.

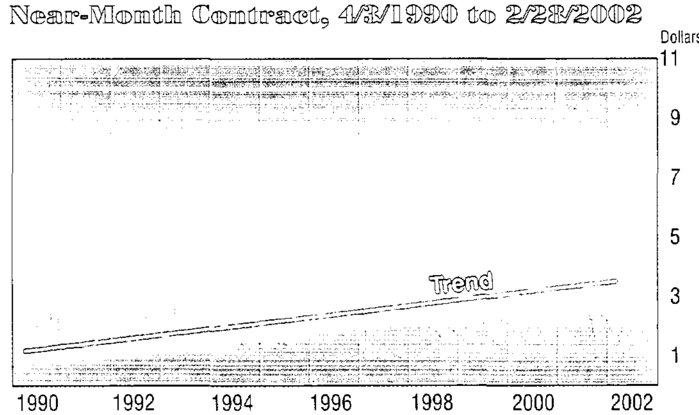
The real story of 2001 becomes evident only as one looks beyond the short-term financial results into the activities that have created new opportunities for us in 2002 and beyond. During the first quarter of 2001, we acquired our newest domestic core area, the Lake Washington Area located in Plaquemines Parish, Louisiana. One of the most exciting aspects of this area is its tremendous potential for enhancing long-term reserves and production. Multiple sands at various horizons are deposited around a large salt dome, many currently producing and others still unexploited. During 2002, we intend to double or even triple our production in the area through development drilling. These wells will have relatively long production lives and therefore will impact the Company for many years.

NYMEX Crude Oil Futures
Near-Month Contract, 1/1/1990 to 2/28/2002

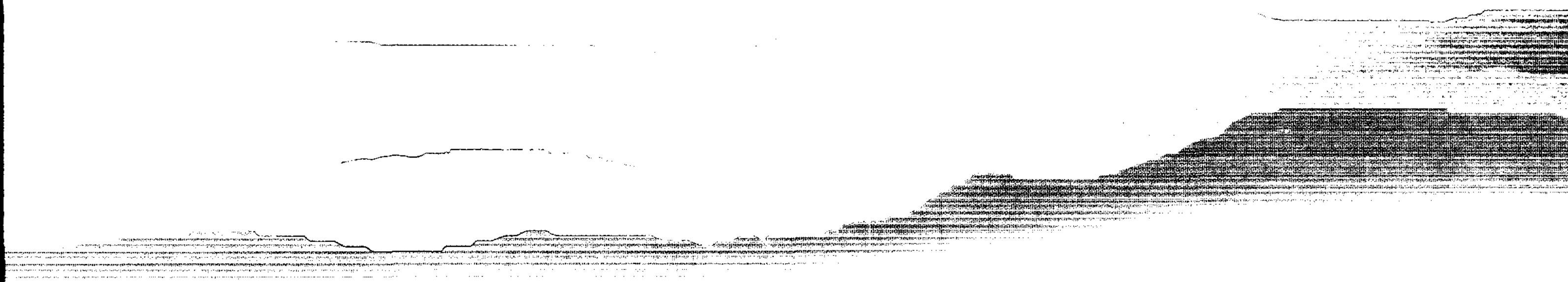


After peaking toward the end of 2000, NYMEX crude oil prices fell steadily throughout 2001.

NYMEX Natural Gas Futures
Near-Month Contract, 4/3/1990 to 2/28/2002



NYMEX natural gas prices reached an all-time high at the end of 2000 and fell sharply throughout 2001.



Given current low prices, we have elected to greatly curtail development drilling in our other domestic core areas. However, each area has a sizeable inventory of drilling locations that are available to increase production when prices improve. We also have a significant inventory of exploratory prospects, some of which may be marketed to other companies for a promoted interest. The rest will provide upside potential as oil and gas prices rebound.

In New Zealand, we have expanded our operation with a recent acquisition, in January 2002, of four producing fields known collectively as the TAWN properties. With this acquisition, we have become a significant oil and gas producer in that country. We have also completed construction of our new Rimu Production Station, and when it goes on line we will add production from the Rimu/Kauri Area. This gives us considerable potential for both near-term and long-term growth. Moreover, our TAWN assets give us several synergies with our Rimu/Kauri assets, including production facilities and pipelines with excess capacity that could facilitate transportation and marketing of Rimu/Kauri production in the future.

From the 12 wells we have drilled in the Rimu/Kauri Area, it has become clear that the area is very geologically complex. It is also clear that it has multiplay opportunities with extraordinary long-term potential. To date, our wells in the Rimu/Kauri Area have found oil and gas shows in at least ten different geological horizons. The Company continues to believe that this area has long-term reserves potential in excess of 250 million barrels of oil equivalent, or 1.5 trillion cubic feet of natural gas equivalent. We now hold a 95% interest in the Rimu/Kauri permit area after recently purchasing additional interests in two petroleum exploration permits from a subsidiary of Antrim Energy for 220,000 shares of Swift Energy common stock. In 2002, we will be looking for a strategic partner for developing the Rimu/Kauri Area. We plan to sell up to a 25% interest in the permit, retaining at least a 70% interest.

In addition to the Rimu/Kauri discovery, we have a number of exploratory prospects in New Zealand with outstanding reserves potential. These prospects provide us with excellent exploratory potential located along the eastern edge of New Zealand's Taranaki Basin.

Our optimistic outlook for the future does not disregard the low product prices we have experienced during the first quarter of 2002. However, we know that ever since Colonel Drake drilled the first oil well in 1859, the oil and gas industry has experienced price swings. Current prices are low, but the rapid rise of oilfield service costs in 2000 and 2001 shows that the industry faces some severe capacity limitations. Domestic producers are cutting their capital budgets, and cuts in drilling activity usually lead to production declines in a relatively short time period. When the economy rebounds, oil and gas demand is likely to rise, which should eventually lead to another round of rising prices. With that in mind, we are focused during 2002 on continuing to build a high-quality production base with long-lived assets and significant upside potential. We see new horizons of opportunity before us, and our goal is to transform them into new horizons of achievement.

A. Earl Swift
Chairman

Terry E. Swift
President and
Chief Executive Officer

STRATEGIC HORIZONS

Swift has established a proven track record for building shareholder value. From 1991 through 2001, the Company's year-end stock price rose at an average compounded rate of 15% per year, compared to 12% for the Dow Jones Industrial Average, 11% for the S&P 500, and 10% for the Russell 2000.

2001 Industry Environment. Long-term yardsticks are critical for fully measuring the value of a company operating in an environment of volatile price cycles. On December 27, 2000, natural gas futures prices on the New York Mercantile Exchange (NYMEX) reached an all-time record high of $9.98 per MMBtu, but by year-end 2001, prices had fallen to $2.57 per MMBtu, a 74% decline. NYMEX oil futures prices fell 38% from a January 19 high of $32.19 per barrel to $19.84 per barrel at the end of the year.

A major cause of falling product prices was the nation's first economic downturn in a decade, which deepened following the September 11 tragedy. The economic slowdown helped cause U.S. oil consumption to decline slightly for the first time in 10 years and helped push down natural gas consumption by 5%.

Even as consumption began to fall, high commodity prices triggered a surge in finding and operating costs, as companies competed for equipment and manpower. When commodity prices continued to decline, companies were slow to react because of prior commitments, causing oilfield service costs to remain elevated. In mid-July, when the number of active U.S. natural gas drilling rigs reached a long-term high, natural gas prices were already down over 70% from their peak.

Swift's response to these challenges has been to build a balanced portfolio of long- and short-lived properties with identified future drilling locations that position the Company to take advantage of product pricing cycles.

Long-Term Outlook. Over the long-term, the outlook for the oil and gas industry in the United States and abroad is quite promising. As the economy recovers and energy demand revives, oil and gas prices are expected to rebound from current lows.

The nation's use of natural gas is expected to continue growing faster than that of any other fuel, driven by natural gas-fired electricity generation. Between 1999 and 2020, the U.S. Energy Information Administration estimates that electric utilities will account for more than half of the projected increase in U.S. natural gas consumption. As demand grows, the most pressing question will be whether supply can keep pace. Growth in Canadian imports, which accounted for over half of the growth in U.S. consumption during the last decade, is expected to slow over the next 10 years, and challenges for finding new domestic reserves became apparent in 2001 when the industry success rate for exploratory wells fell to 31%, one of the lowest levels in several years.

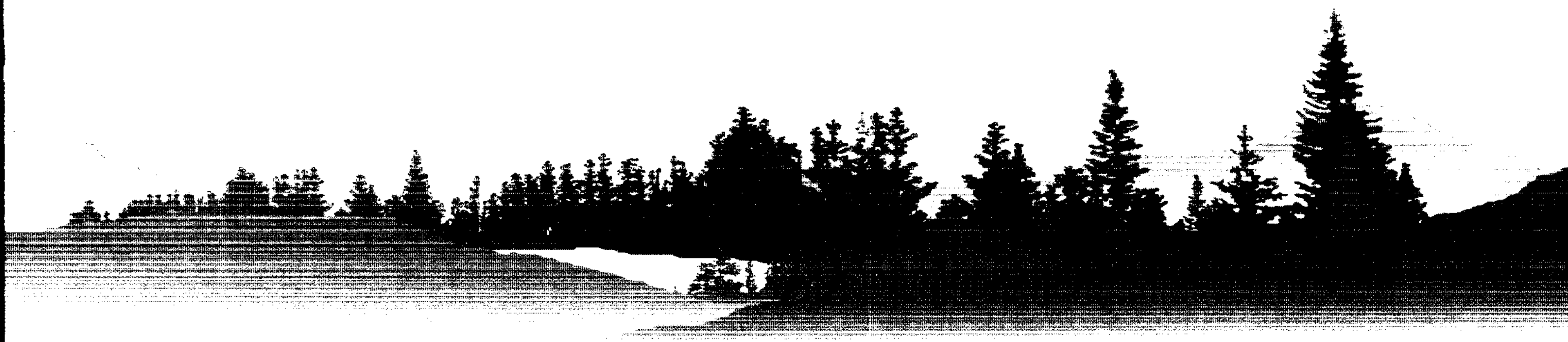
Many industry sources project world oil production to peak within a range of 5 to 25 years, and before the peak is reached, growth in global production rates will slow. Meanwhile, demand is projected to grow significantly in developing regions such as Asia and Central and South America.

PRODUCING HORIZONS

Operating Domestic Core Areas

Over 80% of Swift Energy's record production of 44.8 Bcfe in 2001 came from the producing horizons in the Company's four domestic core areas of operation. Three of the areas continue to be the AWP Olmos Field in South Texas, the Masters Creek Area in Central Louisiana, and the Brookeland Area in East Texas, with a fourth, the new Lake Washington Area in South Louisiana, added during the year.

In addition to optimizing the performance of wells already in production, Swift focuses its domestic development drilling activities in these core areas. During 2001, the Company drilled 36 development



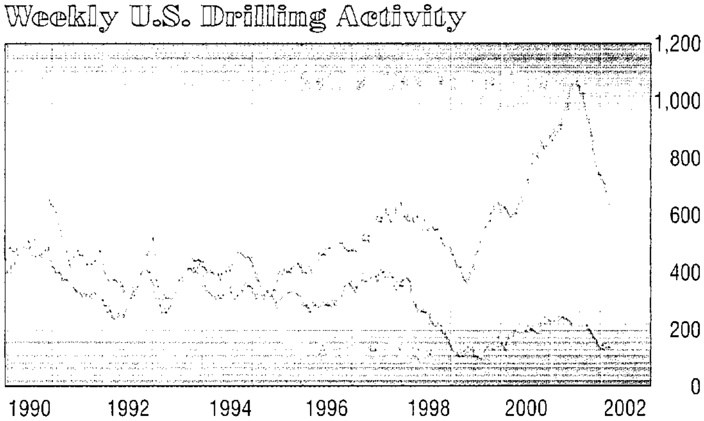
wells, serving as the operator of 30 of them. All of the 36 wells were successful, and 33 of them were drilled in the core areas. As noted in the discussion below, the Company's development drilling in 2002 will be concentrated in the Lake Washington Area.

The AWP Olmos Area. Swift's operation in the AWP Olmos Field in McMullen County, Texas, which began on a 4,900-acre leasehold in 1989, now covers 28,562 net acres. The field produces from the tight Olmos sand, a depletion-driven reservoir characterized by very low permeability, and the formation around each well must be hydraulically fractured in order to provide pathways for the hydrocarbons to flow into the wells.

Swift has consistently improved its formation-fracturing techniques, learning in the process that reducing the size of the fractures around new wells and performing subsequent refractures improves the percentage recovery of reserves per well. The Company also determined that production improves with the installation of small-diameter coiled tubing (velocity strings) in the wells to accelerate the upward flow of the gas and gas liquids.

During 2001, the Company successfully completed 11 new AWP development wells, each with a 100% working interest. In addition, it performed 26 refractures and installed 19 velocity strings. Nine

Weekly U.S. Drilling Activity



Drilling activity in the United States reached the highest peak in several years during mid-2001, driving up the cost of oilfield services.

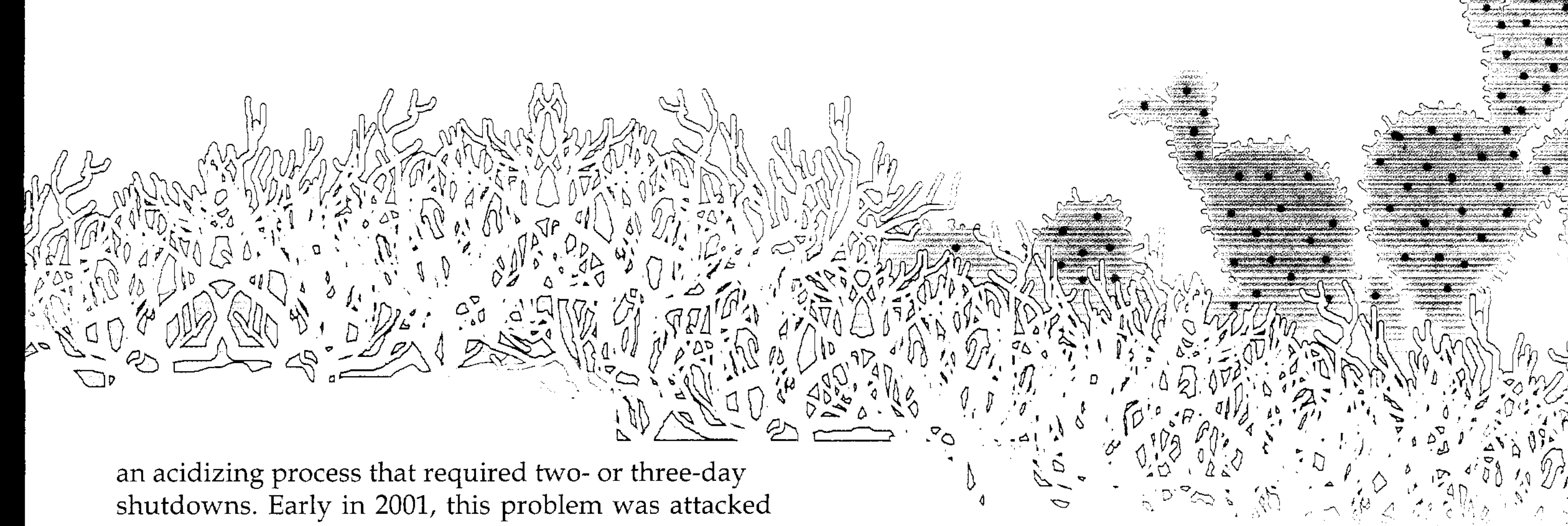
refractures and 30 coiled tubing installations are currently scheduled for 2002.

At year-end 2001, Swift was operating 492 wells in the field, which accounted for 29% of the Company's total 2001 production. The field also held 32% of the Company's proved reserves (38% of its domestic reserves) and 122 proved undeveloped locations awaiting future drilling. With each new well expected to have a productive lifetime of 15 to 20 years, the AWP Olmos Field should be a major production area for the Company for many years.

Masters Creek Area. The Masters Creek Area, acquired in 1998 and located in Rapides Parish and Vernon Parish, Louisiana, has two major fields, the Masters Creek Field and the South Burr Ferry Field, and several smaller fields, all producing primarily from the Austin Chalk formation. Like the Olmos sand, the Austin Chalk formation is generally depletion driven; however, it also contains natural vertical fractures which frequently become deposits for oil and gas accumulations. Tapping these deposits requires that a vertical hole first be drilled down to the Austin Chalk horizon and that the well bore then be gradually turned in a horizontal direction to intercept multiple fractures.

Because of the pooling of the oil and gas within the fractures, Austin Chalk wells are well known for their high initial production rates and early payout followed by sharp declines. In the Masters Creek Field, however, the wells have longer lives. In fact, two wells in the field have each already flowed over 2 million BOE, and five other wells have flowed over 1 million BOE. This is attributed to the fact that water is pushing the oil and gas from below and making a cleaner sweep of the reservoir.

While the large volumes of water aid production, they necessitate the construction of water disposal facilities that increase production costs. Also, the water causes a buildup of scale along the interior walls of the well bore tubulars that until recently could be removed only with



an acidizing process that required two- or three-day shutdowns. Early in 2001, this problem was attacked with a procedure that consists of pumping up to 25 barrels of a chemical into the hole and then flushing it out into the formation with about 2,000 barrels of water following the chemical injection. Production can be resumed within a few hours, with the chemicals remaining in the formation and retarding the buildup of scale for several months.

A study is currently under way to further improve operations in this area by minimizing the costs of placing new wells on line. With the boundaries of the field now largely defined, future wells will probably be offsets close enough to older wells that facilities can be shared, thus eliminating the need to construct additional long flow lines and tank batteries.

During 2001, seven successful development wells were drilled in the Masters Creek Field and two in the South Burr Ferry Field, all with high Swift working interests (averaging 88%). At year-end, Swift was the operator of 90 wells in the Masters Creek Area, which accounted for 34% of the Company's total 2001 production and held 16% of its total year-end proved reserves (19% of its domestic reserves). The area also has 18 proved undeveloped locations available for drilling in future years.

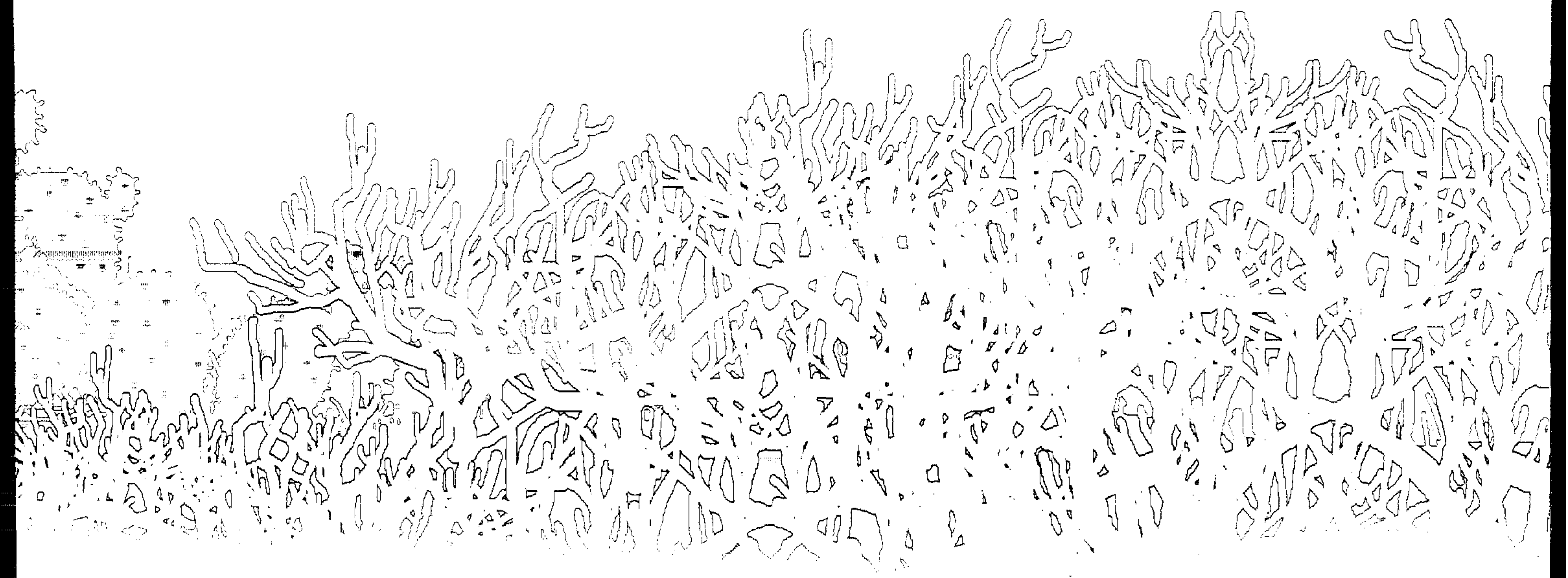
Brookeland Area. Swift's Brookeland Area, also acquired in 1998 and located in Newton County and Jasper County, Texas, also produces from the Austin Chalk trend (in the Brookeland Field), but at shallower depths. Because of the shallower horizons, the capital costs of drilling a horizontal well in the Brookeland Field are only one-third to one-half the costs of wells in the Masters Creek Field. Also, their associated reserves are less, averaging from 3 to 5 Bcfe per well.

During 2001, Swift participated in nine successful development wells drilled in the Brookeland Field, six of them as the operator with retained working interests of 95% to 100%. At year-end, the Company was

Distribution of Swift Energy's Proved Reserves
As of December 31, 2001

	Proved Reserves[b] (Bcfe)			Percent of Company's Reserves	Percent Natural Gas	Percent Undeveloped
	Developed	Undeveloped	Total			
Texas:						
AWP Area[a]	134.0	73.5	207.5	32.1%	73.8%	35.4%
Brookeland Area[a]	26.3	32.8	59.1	9.1%	40.1%	55.6%
Other Texas	34.1	41.1	75.2	11.7%	88.4%	54.6%
Total Texas	194.4	147.4	341.8	52.9%	71.2%	43.1%
Louisiana:						
Lake Washington Area[a]	25.3	47.2	72.5	11.2%	5.0%	65.1%
Masters Creek Area[a]	52.5	52.3	104.8	16.2%	25.7%	49.9%
Other Louisiana	0.9	0.0	0.9	0.1%	87.2%	0.0%
Total Louisiana	78.7	99.5	178.2	27.5%	17.6%	55.8%
Other States & Federal Offshore	16.7	7.2	23.9	3.8%	58.6%	30.1%
Total Domestic	289.8	254.1	543.9	84.2%	53.1%	46.7%
New Zealand[a]	34.4	67.5	101.9	15.8%	35.7%	66.2%
Total Company	324.2	321.6	645.8	100.0%	50.3%	49.8%

[a]For a discussion of these areas, see pages 6-15 and pages 51-56.
[b]See definitions of proved reserves, proved developed reserves, and proved undeveloped reserves on pages 59-60.



operating 67 wells in the field, which held 9% of the Company's proved year-end reserves (11% of its domestic reserves) and contributed 15% of the Company's 2001 production. The field has 17 proved undeveloped locations for future drilling.

Lake Washington Area. Swift's new core operating area is located in the Lake Washington Field in Plaquemines Parish, Louisiana. This field, covered by a lake, produces from multiple Miocene sands ranging in depth from 2,000 feet up to 10,000 feet and has the potential for deeper exploration prospects. Because this area also has a flatter production curve than Swift's other core areas, as well as a high potential for development and revitalization at comparatively lower capital costs, it will be the focus of the Company's domestic drilling and operational improvements during 2002.

Distribution of Wells in Which Swift Owned Interests
As of December 31, 2001

	Wells Operated by Swift[b]	Wells Operated by Others	Total Wells[b]	Percent of Swift's Year-End Proved Reserves	Percent of Swift's 2001 Production
Texas:					
AWP Area[a]	492	4	496	32.1%	29.1%
Brookeland Area[a]	67	34	101	9.1%	14.5%
Other Texas	118	173	291	11.7%	12.2%
Total Texas	677	211	888	52.9%	55.8%
Louisiana:					
Lake Washington Area[a]	61	20	81	11.2%	2.7%
Masters Creek Area[a]	90	39	129	16.2%	34.1%
Other Louisiana	7	35	42	0.1%	3.3%
Total Louisiana	158	94	252	27.5%	40.1%
Other States & Federal Offshore	14	76	90	3.8%	3.0%
Total Domestic	849	381	1,230	84.2%	98.9%
New Zealand[a]	5	--	5	15.8%	1.1%
Total Company	854	381	1,235	100.0%	100.0%
Percent of Reserves	95%	5%			
Percent of Production	83%	17%			

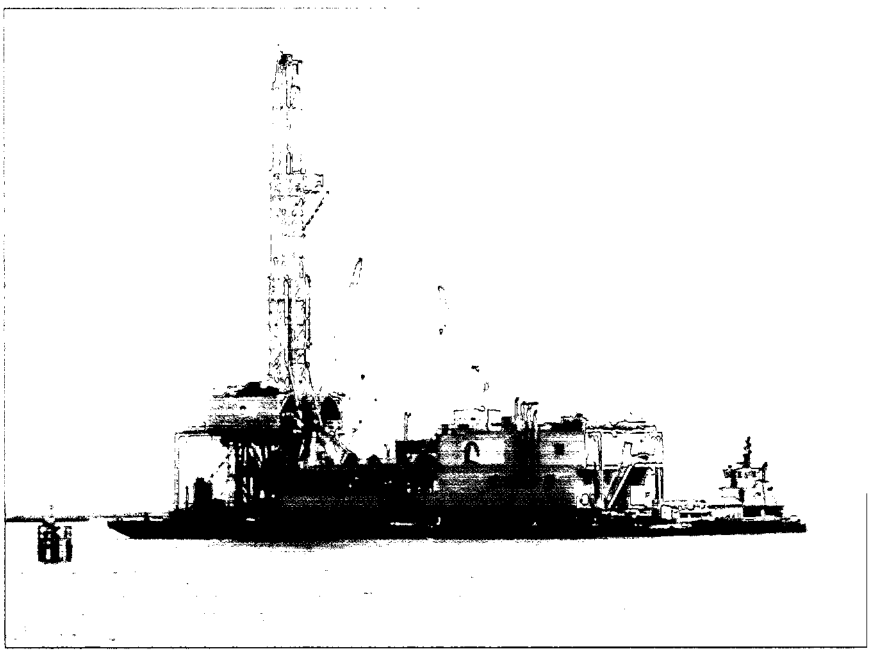
[a]For a discussion of these areas, see pages 6-15 and pages 51-56.
[b]Swift is the operator of 828 producing wells and 26 service wells. The Company has interests in 1,187 producing wells and 48 service wells.

Swift's acquisition of the Lake Washington properties was effective March 1, 2001, with the Company paying $30.5 million to Elysium Energy, LLC, for proved reserves estimated at the time to be 7.1 million barrels of oil and 3.7 Bcf of natural gas, as well as some leasehold acreage. With the acquisition, Swift became the operator and 100% working interest owner of about 20 producing wells. Also with the acquisition, Swift received 100% interests in over 30 shut in or temporarily abandoned wells with the potential of being reinstated as producers. In addition, it received working interests in about 20 wells operated by another company. At the time of the acquisition, production from the area was approximately 1,000 BOE per day net to the purchased interests.

Discovered in the 1930s and operated by major oil companies whose real interests were offshore, the Lake Washington Field has large

unexploited areas. The field surrounds a deep salt dome whose center approaches the surface, and it is heavily faulted with a large number of potential traps for oil and gas that range in size from less than 5 acres to as much as 160 acres. Within the traps, whose depths increase with increasing distances from the dome's center, are multilayers of potential pay sands, many of them hundreds of feet thick.

Previous operators concentrated their drilling efforts on the north and east sides of the salt dome away from the



A tugboat tows a barge-based rig to a drilling location on Lake Washington. Lake water depths at well locations are typically 6 to 11 feet.

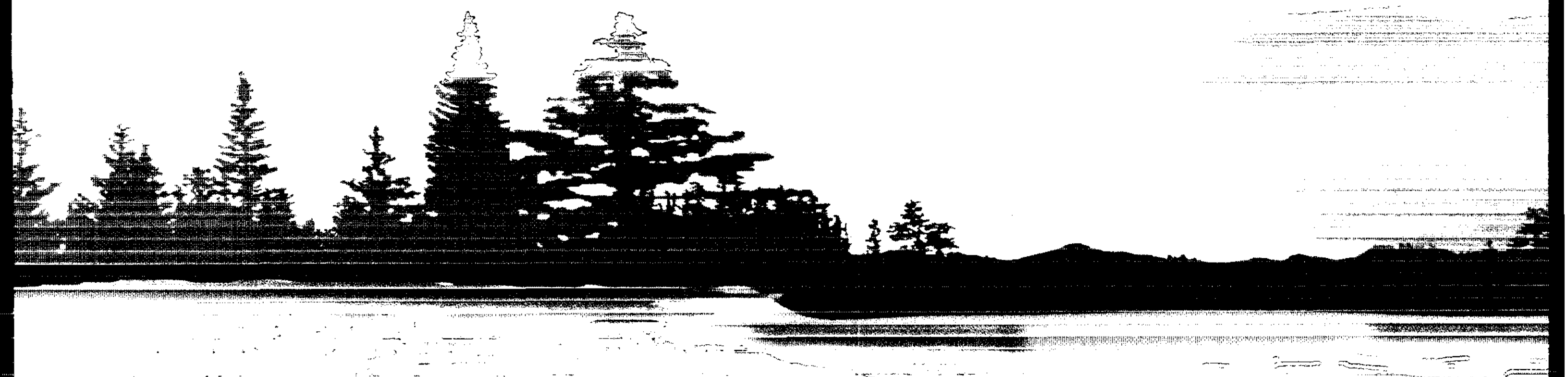
"attics" of the fault blocks, that is, the areas in which the sands have reached their highest (most shallow) positions and are closest to the salt dome's surface. Swift also has been concentrating on the north and east sides, but with increasing attention given to the attics where the Company's geological mapping indicates the potential presence of both oil and gas. During the last half of 2001, the Company successfully drilled one exploratory well and four development wells in the field, including one attic well, all of which boosted the year-end production in the area to about 1,700 barrels of oil and 1 million cubic feet of gas per day. (Additional gas produced is used for oil lift operations.)

Since year-end 2001, two additional successful development wells have been drilled, both as attic wells. The full 2002 program will include 20 development wells, some of which will be located on the under-exploited west and south sides. At year-end, Swift had identified 29 proved undeveloped locations in the field.

The Lake Washington reservoirs are strongly water driven, with high volumes of salt water produced with the oil. Currently, the water is separated out at the processing plant at Swift's expense. Salt water disposal costs will be greatly reduced, however, as the Company converts some of the nonproducing wells to disposal wells.

The most challenging operational problem in Lake Washington is to prevent reservoir sand from clogging the inflow of hydrocarbons into the producing wells. This problem is typically combatted with "gravel packs" created by pumping large-grain sand down the well bore and back up into an annulus formed between a mesh screen and the inner surface of the well casing. This prevents the smaller-grain sand from entering the well bore while still allowing the oil and gas to flow through the gravel pack.

At year-end 2001, Swift was the operator of 61 wells in the Lake Washington Area, which held 11% of the Company's total proved year-end reserves (13% of its domestic reserves) and contributed 3% of its 2001 production. Both the reserves and the production are expected to increase significantly during 2002.



MULTIPLE HORIZONS

Operating New Zealand Core Areas

Swift Energy now has two core areas of operation in the Taranaki Basin of New Zealand's north island, one known as the Rimu/Kauri Area and the other as the TAWN Area.

The Rimu/Kauri Area resulted from the Company's successful exploration and development of its Rimu prospect begun in late 1999 plus the exploration and initial development of its Kauri prospect in 2001. The initial wells on the two adjacent prospects are separated by approximately 5 miles, and the Company believes that the wells have tapped connecting fields that represent a major multizone discovery.

The TAWN Area was added in January 2002 when Swift purchased Southern Petroleum (New Zealand) Exploration, Ltd. (Southern NZ), from Shell New Zealand (Shell NZ). The acquisition provided interests in four producing fields north of the Rimu/Kauri Area, as well as considerable infrastructure.

With these two core areas of operation, Swift has become a significant producer in New Zealand's oil and gas industry. According to the New Zealand Ministry of Economic Development, the TAWN properties alone accounted for approximately 4% of New Zealand's oil production and approximately 4.5% of its natural gas production during the year ending March 2001. Production from the Rimu/Kauri Area will increase these percentages. Moreover, the Rimu/Kauri Area holds considerable potential for both near-term and long-term growth with production from multiple geological horizons. Such growth is encouraged by the New Zealand government, since the country is a net importer of oil and is facing near-term declines in production from the Maui Field, its major source of natural gas supply.

Rimu/Kauri Area. Swift's Rimu/Kauri Area is located in New Zealand's petroleum exploration permit area PEP 38719 in the southern portion of the Taranaki Basin on the west coast of the north island (see map on page 12). This area covers approximately 50,000 net acres, extending both onshore and offshore. In March 2002, the Company increased its interests in the area from 90% to 95% by purchasing a 5% interest owned by a subsidiary of Antrim Energy Inc. of Canada. The remaining 5% is owned by a subsidiary of Bligh Oil and Minerals Ltd. of Australia.

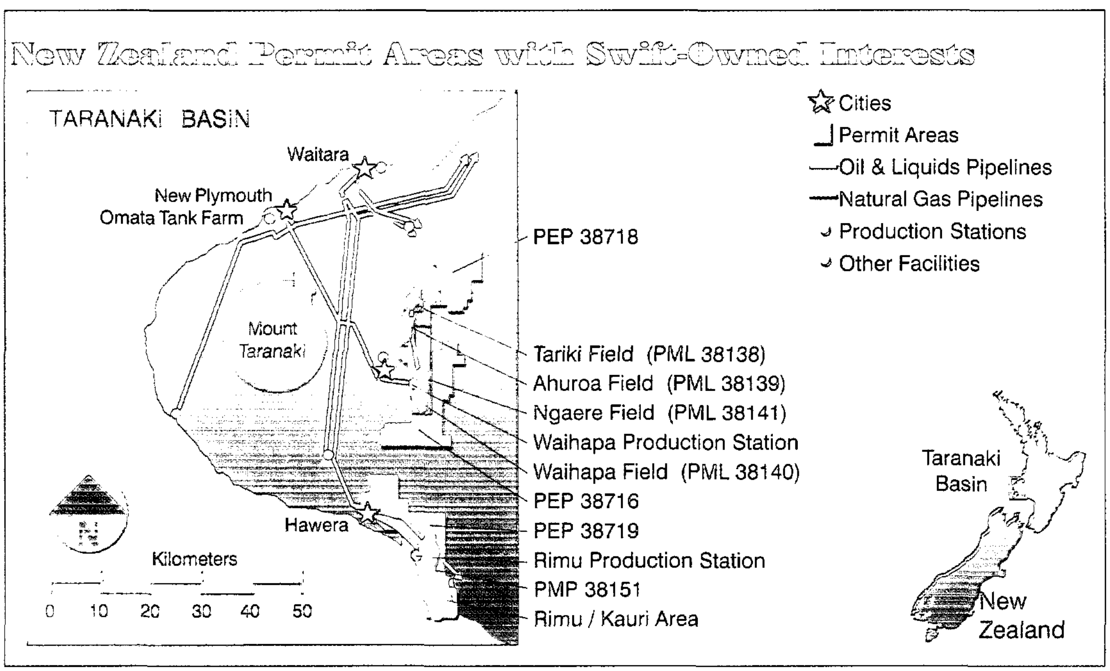
Reserves Estimates. During 2001, Swift's delineation activities, both exploratory and developmental, revealed that the Rimu/Kauri Area is more geologically complex than originally envisioned. Swift believes the area has substantial reserves potential; however, the Company has adopted a conservative approach to booking proved reserves. After reserves corresponding to the working interests owned by others were deducted, Swift's net year-end proved reserves for the area were approximately 17 million BOE (102 Bcfe), representing a decline of 17% from those reported at year-end 2000. However, the Company continues to believe that this area has long-term reserves potential in excess of 250 million barrels of oil equivalent, or 1.5 trillion cubic feet of natural gas equivalent.

To date, the identified reservoirs and potential reservoirs (with oil and gas shows in various wells) in the Rimu/Kauri Area include (starting with the oldest) the Maitai (Permian); Murihiku (Triassic); Rakopi and North Cape (Cretaceous); Mangahewa (Eocene); Rimu limestone and Tariki sandstone (Oligocene); Kauri sandstone and Urenui sandstone (Miocene); and Manutahi sandstone (Pliocene). All of these reservoirs, except the Rimu limestone, are sandstone reservoirs.

The Taranaki Basin is located in a thrust belt where the eastern plate of the earth's crust moved over the western plate. As a result, some hydrocarbon-bearing zones are repeated at certain drilling locations. For example, some of the Rimu wells have found the Tariki sandstones and the Rimu limestones in both the upper and lower plates.

Drilling Activities. Through February 2002, Swift had drilled 12 wells in the Rimu/Kauri Area—eight Rimu wells and four Kauri wells (see table on page 14). The initial discovery well, the Rimu-A1 well, was drilled during the fourth quarter of 1999 and was successfully tested in the Upper Tariki sandstone, with additional hydrocarbon shows in the Lower Tariki sandstone and the Lower Rimu limestone.

In 2000, the Rimu-B1 and -B2 wells were drilled from a second (B) pad. The Rimu-B1 had hydrocarbon shows in five different zones—the Upper Tariki sandstone, the Upper Rimu limestone, the Maitai metasediment, the Lower Tariki sandstone, and the Lower Rimu limestone—and was successfully tested (in March 2001) in the Upper Rimu limestone. The Rimu-B2 encountered hydrocarbon shows in the Upper Tariki sandstone and the Upper Rimu limestone and was successfully tested in the Rimu limestone.



During 2001, six wells were drilled: the Rimu-A2, -A3, and -B3 and the Kauri-A1, -A2, and -B1. Although the Rimu-A2 well confirmed the presence of an Upper Tariki section with high-quality reservoir rock, the section was 300 feet lower than in the Rimu-A1 well and was found to be water bearing. Early in 2002, it was sidetracked as the Rimu-A2A well, again reaching the Tariki sand and currently awaiting completion.

The Rimu-A3 well was confirmed to be a producer in the Upper Tariki formation. In addition, logging results confirmed the presence of the Upper Rimu limestone, along with other potential horizons at shallower depths where hydrocarbon shows were encountered.

The Rimu-B3 well targeted but failed to reach either the Upper Tariki sand or the Upper Rimu limestone in the upper thrusted section. In early 2002, the well was sidetracked as the Rimu-B3A well and was again unsuccessful.

The Kauri-A1 well was initially tested in the Upper Tariki sand, but was temporarily plugged above the sand so that three distinct areas of the shallower Kauri sand could be tested. The Kauri sand consists of 872 gross feet of multiple interbedded sections of sandstones and claystones that yielded good oil and gas shows as the Kauri-A1 well was being drilled. This same interval was also encountered in all of the Rimu wells with varying degrees of hydrocarbon shows, but it had greater sand development and better mud log shows in the Kauri-A1 well. Completion of the Kauri-A1 well is scheduled for 2002.

The Kauri-A2 well was drilled to test the shallow Manutahi sand observed in the Kauri-A1 well. The well tested as a successful producer, but sand migration into the well bore limited production rates. To control the sand inflow, the Company gravel packed the well.

In late 2001 and early 2002, the Kauri-B1 well, a shallow Manutahi step-out exploratory well, was drilled. Although unsuccessful, it helped to define the field's boundaries. Also in early 2002, the Kauri-A3 well was drilled and is awaiting testing in the Manutahi sand.

Swift's budgeted development program for the Rimu/Kauri Area in 2002 includes expenditures for two completions, one of which is the Kauri A-1 well, and six development wells, one of which is a deep offset to the Kauri-A1 well.

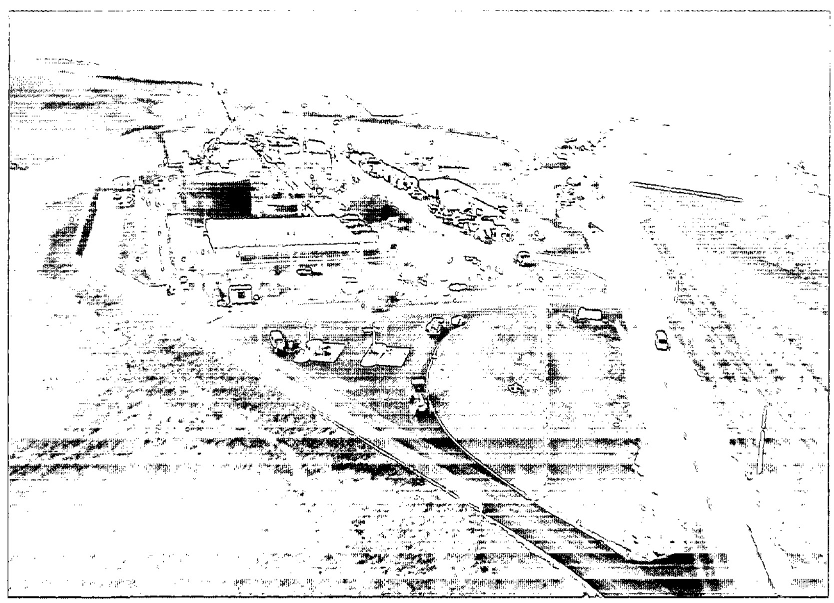
Long-Term Development. Early in 2002, Swift was awarded petroleum mining permit PMP 38151 by the New Zealand Ministry of Economic Development for the development of the Rimu discovery over a 5,524-acre area for a primary term of 30 years. The Company plans to add up to three additional drilling pads in the permit area (for a total of five pads) with each able to handle multiple wells. Nine additional wells are currently planned within the mining permit, one gas injection well and eight development wells targeting the Upper Tariki and Lower Tariki sandstones and the Upper Rimu limestone. The total capital expenditures over the life of the project are expected to be approximately US $80 million.

Rimu Production Station. Early in 2002 Swift completed the construction of its Rimu Production Station near the Rimu/Kauri Area, and regular commercial production from the Rimu wells is scheduled to start following the commissioning of these facilities in March or April 2002. Beginning commercial production approximately 28 months after its initial discovery, Swift will be setting a New Zealand record compared to other companies who have required 4 to 11 years to initiate production.

The station is designed to initially handle 3,500 barrels of oil and 10 MMcf of natural gas per day (about 31 MMcfe per day) during its first phase of operation. However, with minimal additional capital the plant's capacity can be increased to 8,250 barrels of oil and 20 MMcf of gas per day (approximately 70 MMcfe per day) with options for even further expansion.

Marketing. During 2001, Swift produced and sold 84,261 barrels of oil from the area while conducting production testing, primarily at the Rimu A and B pads. No gas was sold from the area in 2001, but Swift has an agreement with Genesis Power Limited (Genesis), a New Zealand state-owned enterprise, to provide Genesis with 40 petajoules (approximately 38 Bcf) of natural gas over a 10-year period once the Company begins commercial gas production.

TAWN Area. Swift completed its acquisition of Shell NZ's affiliate, Southern NZ, in January 2002, obtaining 96.76% working interests in four petroleum mining licenses covering producing oil and gas fields located approximately 17 miles north of the Rimu discovery. The properties are collectively identified as the TAWN properties, an acronym derived from the first letters of the field names—the Tariki Field (PML 38138), the Ahuroa Field (PML 38139), the Waihapa Field (PML 38140), and the Ngaere Field (PML 38141). The Tariki Field and Ahuroa Field both produce from the Tariki



Swift Energy's Rimu Production Station is scheduled to become operational with its commissioning in March or April.

Swift Exploratory and Development Wells Drilled in PEP 38719 Through February 2002

Well / Type	Year	Total Depth (feet[a])	Status[b]	Formations
Exploratory Wells				
Rimu-A1	1999	16,493	Producer	Upper Tariki sand
Kauri-B1	2001	4,101	Dry	Targeted Manutahi sand
Kauri-A1	2002	14,764	To Be Completed	Kauri & Upper Tariki sands
Development Wells				
Rimu-B1	2000	14,272	Producer	Upper Rimu limestone
Rimu-B2	2000	11,650	Producer	Upper Rimu limestone
Rimu-A2	2001	15,407	Dry	Targeted Upper Tariki sand
Rimu-A3	2001	12,795	Producer	Upper Tariki sand
Rimu-B3	2001	15,853	Dry	Targeted Upper Tariki sand & Upper Rimu limestone
Kauri-A2	2001	4,199	Producer	Manutahi sand
Rimu-A2A	2002	13,225	To Be Completed	Sidetrack to Upper Tariki sand
Rimu-B3A	2002	15,853	Dry	Sidetrack to Upper Tariki sand & Upper Rimu limestone
Kauri-A3	2002	4,921	To Be Completed	Targeting Manutahi sand

[a]1 foot = 0.3048 meters.
[b]As of December 31, 2001, all of the successful producers in the Rimu/Kauri Area were shut in awaiting the commissioning of the Rimu Production Station.

formation, while the Waihapa Field and Ngaere Field produce from the Tikorangi formation. The acquisition, which also includes hydrocarbon-processing facilities with excess capacity and pipelines connecting the fields and facilities to export terminals and markets, was purchased for US $54.4 million with funds available under the Company's bank line of credit.

Field Assets. The four fields include 17 wells with an estimated first quarter 2002 net production of at least 900 barrels of oil, 27 million cubic feet of natural gas, and 500 barrels of natural gas liquids per day, or a total net production of approximately 35 million cubic feet of natural gas equivalent per day. The combined fields have a contracted minimum deliverability and serve as a swing producer for the electrical demand market in New Zealand. They are producing considerably under their maximum deliverability, which yields a flat production profile and extends the lives of the fields. Drought conditions, as occurred this past summer in New Zealand, and other gas shortfalls will sporadically increase their production volumes. As of December 31, 2001, the reserves associated with the acquisition were estimated to be approximately 62.1 Bcfe, of which 75% was natural gas.

Infrastructure Assets. The TAWN natural gas processing facilities and oil and gas pipelines, together with other infrastructure with current excess capacity, can provide synergies with Swift's Rimu/Kauri Area. Solution gas gathered from an oil facility, the Waihapa Production Station (WPS), flows to the Tariki Ahuroa Gas Plant. The current processing capacity of the WPS facility is over 15,000 barrels of oil and condensate per day and 40 MMcf of natural gas per day. Natural gas processing can be increased significantly with additional compression. A 32-mile (8-inch-diameter) oil export line runs from the WPS to the Omata Tank Farm at New Plymouth, where oil export facilities allow for sales into international markets. A 32-mile (8-inch diameter) natural gas pipeline runs from the WPS to the Taranaki Combined Cycle Electric Generation Facility near Stratford and on to the New Plymouth Power Station.

Swift has a service agreement with a Shell NZ affiliate, the owner of the Omata Tank Farm, to utilize the blending, storage and export capabilities of the facility. Swift and other users will participate in operational planning issues with the operator of the tank farm to maintain or improve the quality of the McKee blend crude oil. All users of the facility will transport crude oil to the farm and receive McKee blended crude oil. The operator of the facility will provide services for a fixed fee per barrel received and other variable costs as required by the agreement. Under the terms of the agreements, crude oil produced from the Rimu or Kauri discoveries will also have access to the Omata Tank Farm.

Marketing. Swift entered into a one-year agreement for Shell NZ to purchase crude oil from the TAWN Area using a reference price of APPI (Asian Petroleum Price Index) Tapis, an internationally recognized crude oil index, which is quoted at least weekly. The price will be adjusted for various fees and premiums. The natural gas from the TAWN properties has been sold under a long-term contract to Contact Energy Limited. Swift will continue to produce and sell natural gas liquids under existing contracts. Fiscal terms for the oil and gas reserves call for a royalty payable to the Crown at an effective royalty rate of approximately 10%.

TAWN Deep Rights. Swift has offered Shell NZ a 50% interest in the future exploration and development of certain deep oil and gas horizons within the TAWN license areas, with Swift remaining as operator of any future drilling. Shell NZ has until early 2003 to elect to participate.

Shell's Rimu Option. Swift has made the strategic decision to sell an interest of approximately 25% in the Rimu/Kauri Area. Effective with the closing of the TAWN acquisition, Swift granted Shell NZ a short-term option to acquire an undivided 25% interest in PEP 38719, which includes the Rimu Kauri Area, as well as a 25% interest in the Rimu Production Station. Regardless of Shell's decision concerning the exercise of this option, Swift intends to monetize a 25% interest in the Rimu/Kauri Area during 2002.

EMERGING HORIZONS

Achieving Long-Term Growth Through Acquisitions and Drilling

Throughout its history, Swift Energy Company has achieved long-term growth through a mix of producing property acquisitions and exploration and development drilling, with the specific mix adjusted to changing industry conditions. When oil and gas prices decrease, property prices usually follow, making the purchase of producing properties with known reserves—and their further exploitation through development drilling—economically attractive. When oil and gas prices increase, seeking new reserves through exploratory drilling becomes a more viable option.

Since the mid-1990s, Swift Energy's acquisition and drilling activities, both development and exploratory, have largely been focused in two distinct regions of the world: one in the United States along the Texas-Louisiana Gulf Coast, and the other in New Zealand in the Taranaki Basin of that country's north island. As a result of these activities, including several carried out in 2001, Swift has established new core areas of operation in both regions and identified other areas for potential growth.

Producing Property Acquisitions. In pursuing acquisitions, Swift focuses on properties in which it can obtain significant working interests and serve as the operator. With operational control, it can better employ its technical and operational expertise to exploit the properties. The Company also seeks properties within a limited number of geographic areas, which enables it to better manage a greater amount of acreage with fewer employees, thereby minimizing the incremental costs associated with increased development drilling and production.

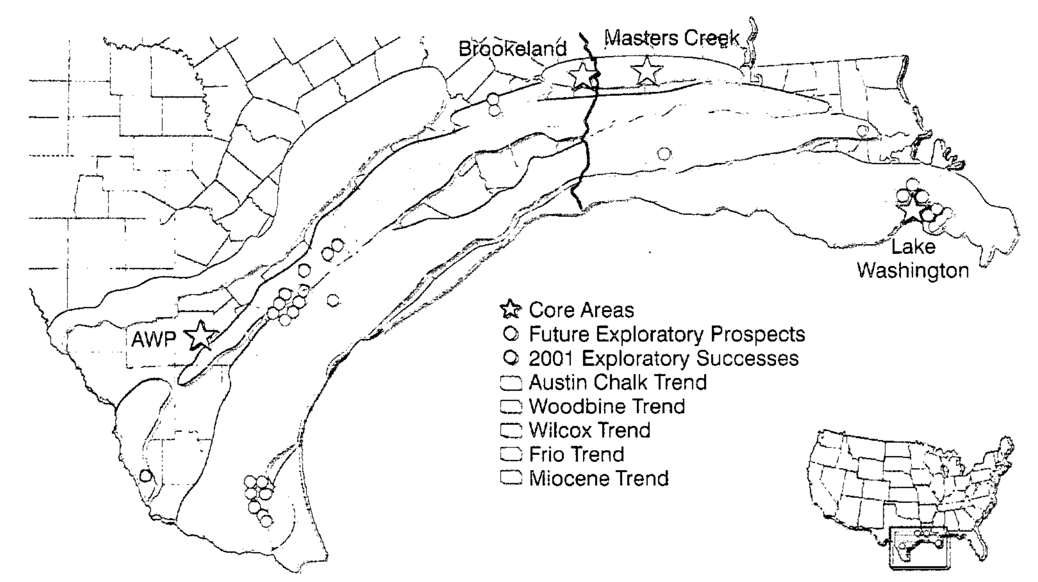
During 2001, Swift's major acquisition in the United States was its $30.5 million cash purchase of 46 Bcfe of proved reserves from Elysium Energy, LLC, in the Lake Washington Field in Plaquemines Parish, Louisiana (see page 9). In addition, the Company repurchased approximately 9 Bcfe of reserves from its former limited partnerships for $7.3 million.

During 2001, Swift also initiated a major acquisition of producing properties in New Zealand which was completed in January 2002. Referred to as the TAWN acquisition and described on page 13, it consisted of the purchase by Swift of Shell NZ's affiliate, Southern NZ, for US $54.4 million. The proved reserves acquired were estimated at 62.1 Bcfe on December 31, 2001.

Domestic Exploration Activities. Swift searches for domestic exploratory prospects that feature a variety of potential hydrocarbon-bearing zones, especially deep zones that were ignored in earlier exploration efforts. Between 1970 and 1999, less than 10% of U.S. wells drilled exceeded depths of 10,000 feet, and less than 2% exceeded 15,000 feet, leaving the deeper horizons largely untapped.

During 2001, Swift drilled nine domestic exploratory wells—seven in Texas, one in Louisiana, and one in Wyoming. Five wells in Texas and one in Louisiana were successfully completed, yielding a 67% success rate. The Company also participated in two non-Swift-operated exploratory wells, neither of which was successful. Thus, the overall success rate for the total 11-well program was 55%, compared to a national average success rate of 31% for the year 2001.

Swift's Core Areas and Future Exploration Prospects



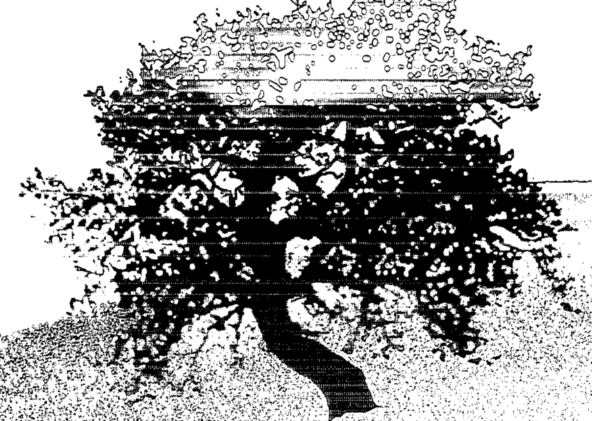
Because of the low commodity prices experienced during the last half of 2001 and continuing into 2002, together with sharply increased service costs, the Company has deferred most of its plans for further exploratory drilling in 2002. (Three unsuccessful wells were drilled early in 2002.) While some of the Company's current inventory of prospects may be marketed to other companies for a promoted interest, others will be kept for future drilling when the industry environment improves. In general, all the prospects are located along the Gulf Coast in the same geological trends in which Swift's 2001 exploratory drilling was focused (see map). The 2001 program is described below.

The Frio Trend. Swift Energy has been focusing on the deep sands of the Frio formation (10,000 to 16,000 feet) in an area that straddles the border of Kenedy County and Willacy County in the southern tip of Texas and is identified as Garcia Ranch. Retaining a 65% working interest, Swift had two discoveries in the area in 2001, one in the Rome prospect in Willacy County at a depth of 16,388 feet, and the other in the Siena prospect in Kenedy County at a depth of 16,300 feet.

The Wilcox Sands. The Company had three discoveries in the Wilcox sands during 2001, two of which were located in Goliad County, Texas: the Nita prospect drilled to a depth of approximately 15,000 feet and the Brandon prospect drilled to a depth of about 13,000 feet. Swift's working interests in the two wells are 73% and 60%, respectively. The third well, in which the Company has a 25% working interest, was in the Falcon Ridge prospect in Zapata County, Texas.

The Woodbine Formation. Swift drilled one well to the Woodbine formation during 2001—in the Lion prospect in San Jacinto County, Texas, down to a depth of 16,300 feet. Although hydrocarbon-bearing intervals were found, the well was determined to be noncommercial with the possibility of re-entry for a future sidetrack well.

The Miocene Sands. Swift successfully drilled its first exploratory well in the Miocene sands in its new Lake Washington Area in Plaquemines Parish, Louisiana—to a



depth of 3,348 feet with a retained interest of 100%. This area has substantial exploration and development potential, with sands extending from shallow depths down to 10,000 feet or more. Current plans are to drill another exploratory well in the area during 2002.

Also in Plaquemines Parish, about 50 miles north of the Lake Washington Area, is the Delacroix area where the Company has also been developing prospects for both shallow and deep horizons in the Miocene sands. The first well in this area, in the Grand Lake prospect, was drilled to a depth of 18,571 feet early in 2002. Though unsuccessful, it may be re-entered for a future sidetrack well.

New Zealand Exploration Activities. In New Zealand, Swift drilled two exploratory wells in 2001 in its Kauri prospect in permit area PEP 38719. One well is awaiting completion in 2002, and the other was unsuccessful. The Company also participated in an exploratory well in PEP 38718 that was temporarily abandoned. These activities are described below, along with other potential prospects.

PEP 38719. The two exploratory wells drilled in the Rimu/Kauri Area were the Kauri-A1 and Kauri-B1 wells. Reaching a depth of 14,763 feet (approximately 4,500 meters), the Kauri-A1 well targeted and found the Upper Tariki sand, which will not be fully tested until 2002. It also found two other potentially productive sands, a thick zone of Kauri sand above the Upper Tariki sand that is also awaiting testing and the more shallow Manutahi sand. A subsequent development well, the Kauri-A2, was successfully drilled to the Manutahi sand. The Kauri-B1 well also targeted the Manutahi sand, at a greater distance from the Kauri-A1 well, but the sand was not productive at this location (see map and discussion of these wells on page 12).

PEP 38719 also holds two other Swift prospects. The Tawa prospect is located northwest of the Rimu/Kauri Area and has as its main targets the Tikorangi limestone, the Kauri sandstone, and the Tariki sandstone. Consisting of a combination of structural and stratigraphic traps, this prospect was developed based upon Swift's analysis of existing three-dimensional seismic data plus two-dimensional seismic data acquired during Company surveys in 1997 and 2000. The Matai prospect is located on the southeast flank of the Tawa prospect. It will target the Moki sandstone. It was originally identified based upon the analysis of two-dimensional seismic data Swift acquired in 2000 and will be further analyzed on the basis of an additional two-dimensional seismic swath obtained over 17 kilometers in February 2002.

PEP 38716. Early in 2002, Swift acquired additional working interests of 7.5% in this area from a subsidiary of Antrim Energy Inc. of Canada, together with 5% additional interests in PEP 38719 (see page 11). As a result, Swift's interests in PEP 38716 increased from 7.5% to 15%. The Company is participating in a non-operated exploratory well to be drilled in the permit area during 2002.

PEP 38718. Swift held a 20% working interest in the exploratory well that was drilled in the Tuihu prospect and temporarily abandoned in PEP 38718 during 2001. In order to determine whether further drilling in the PEP 38718 prospect is advisable, data from the well is being further analyzed, and the seismic data for the prospect is being reinterpreted.

PEP 38730. Because of economic conditions and the opportunities associated with other projects, Swift released its license to PEP 38730, where its Rata prospect was located.

FINANCIAL HORIZONS

Achieving Flexibility in a Volatile Environment

The four cornerstones of Swift's financial strategy are to continually develop a strong credit profile, maintain maximum financial flexibility, preserve a strong balance sheet through an appropriate mix of debt and equity, and effectively manage risk to lessen the impact of the industry's volatile price cycles.

Line of Credit. With the closing of the TAWN acquisition in January 2002, Swift further improved its financial standing by increasing its borrowing base from $200 million to $275 million and its revolving line of credit from $250 million to $300 million through a nine-member bank group. At December 31, 2001, the balance borrowed under the Company's line of credit was $134 million.

These improvements were a cost-effective way of increasing the Company's access to capital. While the credit agreement covers four years and is treated as long-term debt on the balance sheet, the terms of the agreement specify short-term interest rates. The specified interest rate is Swift's choice of the lead bank's prime rate or the adjusted London Interbank Offered Rate (LIBOR) plus the applicable margin based on the ratio of the outstanding balance to the last calculated borrowing base. As of February 28, 2002, the prime rate was 4.75%, and the average LIBOR rate plus its applicable margin was less than 3.5%.

Capital Budget Flexibility. Swift's cash flows from its growing production along with its expanded credit facility and its ability to undertake a debt or equity offering will provide the financial flexibility needed for the Company's 2002 capital budget of approximately $132.5 million, which is exclusive of any additional acquisitions made during the year. The 2002 capital budget is down 52% from the capital expenditures of approximately $275.1 million in 2001, reflecting the Company's reduced level of activity and the expected decline in the cost of oilfield services and equipment, which had risen sharply in 2001 following a surge in demand.

In its 2002 budget, Swift has designated $54.6 million for acquisitions, which covered the TAWN acquisition (see page 15). Should the Company pursue additional acquisitions during 2002, it has the ability to efficiently implement a debt or equity offering.

For exploratory and development activities, Swift has budgeted $39.8 million for its U.S. properties and $19.9 million for its New Zealand properties. An additional $18.2 million has been designated for costs associated with domestic and foreign prospects, including seismic activities. In New Zealand, additional flexibility comes from Swift's opportunity to raise capital by partnering with other oil and gas companies to drill exploratory and development wells in the Rimu/Kauri Area.

Balance Sheet. In 2001, a number of industry and world events impacted Swift and other oil and gas companies, including the economic downturn, the September 11 tragedy, and the demise of Enron Corporation. Despite the effects of these events, Swift exhibited its characteristic resiliency, ending the year in position to take advantage of the opportunities that arise in times of industry downturns, such as the availability of attractive acquisitions.

Price-Risk Management. A portfolio approach to oil and natural gas sales is the focus of Swift's price-risk management. The Company strives for diversity in its oil and natural gas marketing by making sales to a wide variety of purchasers.

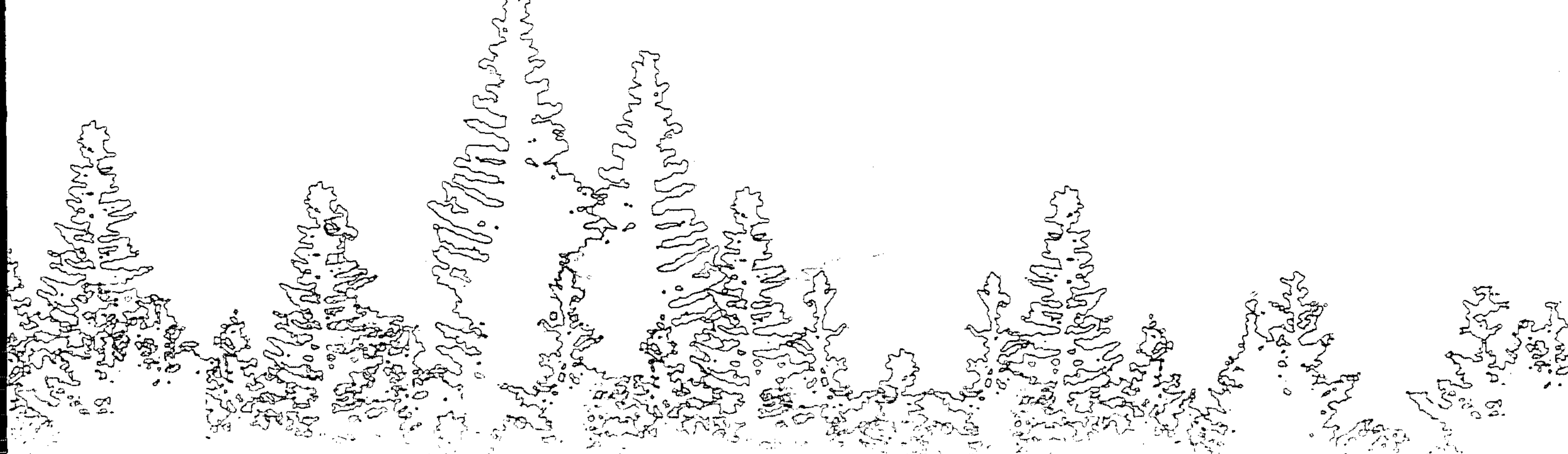
Swift also employs low-cost price floors to safeguard a portion of its oil and natural gas production against rapid price declines. Over the past 10 years, the Company has protected 35% of its production at an average cost of 1.5 cents per Mcfe. In 2001, price-risk management activities resulted in gains of $1.2 million. In addition to price floors, Swift expects that between 17% to 25% of its total annual production in 2002 will be effectively hedged through long-term natural gas contracts in New Zealand.

2002 Outlook. As Swift moves forward in 2002, it has strategies in place to maximize the new horizons of opportunities arising in the current industry environment. Swift projects that the activities planned within its 2002 capital budget will lead to an increase in oil and natural gas production of 10% to 20% and to a decrease in overall expenses per unit of production.

MANAGEMENT HORIZONS

Providing Strong Leadership

Swift has long considered the ongoing development of the Company's leadership, professional staff, and organizational culture to be one of the top responsibilities of upper management.



Management Team. Since its inception, Swift has particularly focused on the continuing development of the Company's management. Swift's policy has generally been to promote employees from within who have been instrumental in past successes.

Consistent with Swift's overall succession plan, in 2001 the board of directors promoted the Company's president, Terry E. Swift, to the additional role of chief executive officer. The former CEO, A. Earl Swift, remains in his role as chairman of the board.

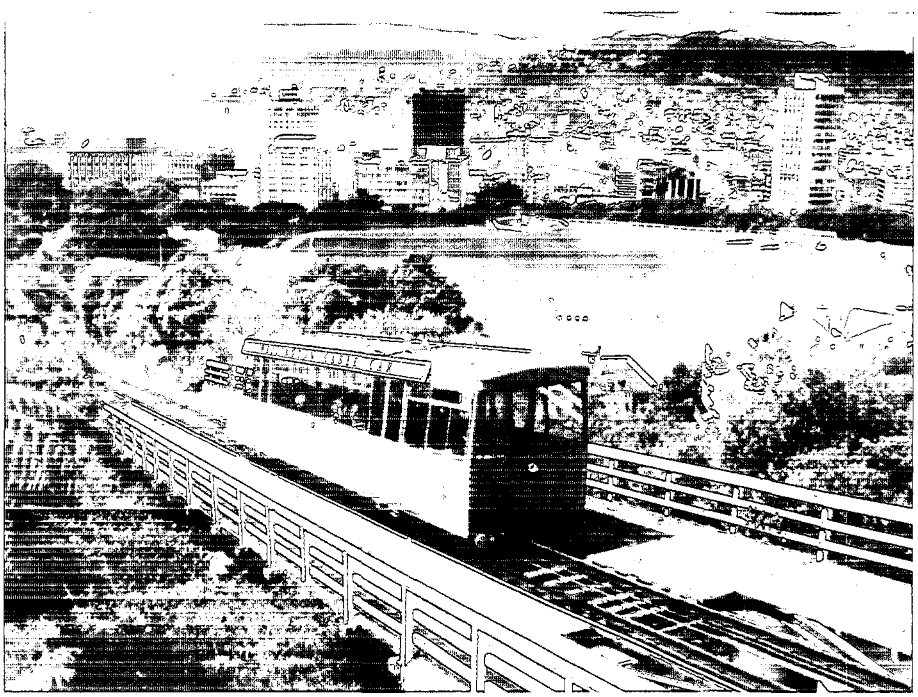
Also during 2001, James R. Stewart, Jr., retired from his position as vice president of drilling and production. In February 2002, Gerald B. Long was promoted to the new position of vice president of production operations. Mr. Long had previously served as director of production operations at Swift.

New Zealand Organization. The same disciplined approach that built the Company's overall management team now guides the development of the Company's staff in New Zealand.

Swift carries out its activities in New Zealand through Swift Energy New Zealand Limited (SENZ), a New Zealand company incorporated on June 6, 1997. SENZ is a wholly owned subsidiary of Swift Energy International, Inc., a Texas corporation, which is in turn a wholly owned subsidiary of Swift Energy Company.

In February 2002, Alan Cunningham was appointed president and chief operating officer of SENZ. He has over 25 years of experience in the oil and gas industry and will be responsible for Swift's day-to-day operations in New Zealand.

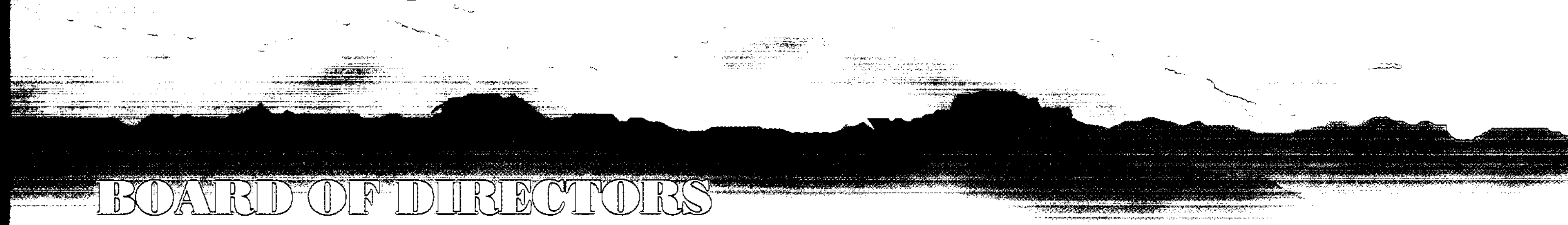
James P. Mitchell, Swift Energy's vice president–land and property transactions, served as interim COO for SENZ prior to Mr. Cunningham's appointment. The former president of SENZ, Donald L. Morgan, continues to serve as SENZ chairman and CEO.



In addition to offices at its two production stations, Swift Energy New Zealand, Ltd., has offices in two New Zealand cities, including the capital city of Wellington pictured above.

In July 2001, Steven B. Yakle became SENZ's chief financial officer and vice president–finance. Mr. Yakle had previously served as Swift's assistant controller–compliance.

With a strong management foundation, SENZ has begun to build its overall organization. Between December 31, 2000, and December 31, 2001, the number of SENZ employees increased from 1 to 16. With the closing of the TAWN acquisition in early 2002, an additional 32 employees have been added to the SENZ staff during the first two months of the year. SENZ currently has New Zealand office locations in Wellington and New Plymonth and at the Waihapa Production Station located in the TAWN Area and at the Rimu Production Station in PEP 38719.



BOARD OF DIRECTORS

A. Earl Swift
Chairman of the Board,
Age 68

Virgil N. Swift
Vice Chairman of the Board, Age 73

Terry E. Swift
President and Chief Executive Officer,
Age 46

G. Robert Evans
Retired Chairman & CEO, Material Sciences Corporation, Age 70

Henry C. Montgomery
Chairman & Founder, Montgomery Financial Services Corp.,
Age 66

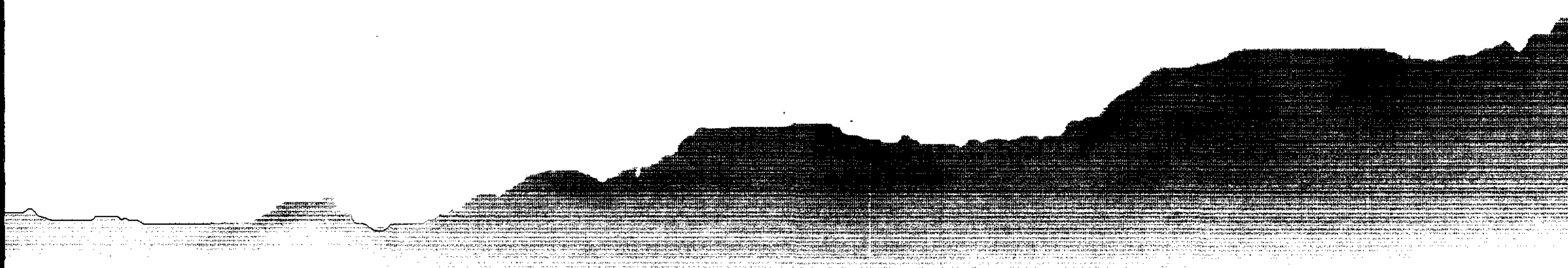
Clyde W. Smith, Jr.
President,
Ascentron, Inc.,
Age 53

Harold J. Withrow
Consultant,
Age 74

Raymond O. Loen
Director Emeritus,
Age 77

Board of Directors Committees:

Audit Committee—Henry C. Montgomery, Chairman, Clyde W. Smith, Jr., G. Robert Evans.
Compensation Committee—Clyde W. Smith, Jr., Chairman, Henry C. Montgomery, Harold J. Withrow.
Conflicts of Interest Committee—Henry C. Montgomery, Chairman, G. Robert Evans, Harold J. Withrow.
Executive Committee—A. Earl Swift, Chairman, Virgil N. Swift, Harold J. Withrow, Terry E. Swift.
Nominating and Corporate Governance Committee—G. Robert Evans, Chairman, Clyde W. Smith, Jr., Harold J. Withrow.
Special Transactions Committee—Harold J. Withrow, Chairman, G. Robert Evans, Henry C. Montgomery, Clyde W. Smith, Jr.



FINANCIAL REPORT

Selected Financial and Operating Data

	2001	2000	1999	1998
Revenues				
Oil and Gas Sales	$181,184,635	$189,138,947	$108,898,696	$80,067,837
Fees and Earned Interests[2]	$427,583	$331,497	$229,749	$333,940
Interest Income	$49,281	$1,339,386	$833,204	$107,374
Other, Net	$2,145,991	$815,116	$709,358	$1,960,070
Total Revenues	$183,807,490	$191,624,946	$110,671,007	$82,469,221
Operating Income (Loss)	$(34,192,333)	$93,079,346	$29,736,151	$(73,391,581)
Net Income (Loss)	$(22,347,765)	$59,184,008	$19,286,574	$(48,225,204)
Net Cash Provided by Operating Activities	$139,884,255	$128,197,227	$73,603,426	$54,249,017
Per Share Data				
Weighted Average Shares Outstanding[3]	24,732,099	21,244,684	18,050,106	16,436,972
Earnings (Loss) per Share—Basic[3]	$(0.90)	$2.79	$1.07	$(2.93)
Earnings (Loss) per Share—Diluted[3]	$(0.90)	$2.51	$1.07	$(2.93)
Shares Outstanding at Year-End	24,795,564	24,608,344	20,823,729	16,291,242
Book Value per Share	$12.61	$13.50	$8.18	$6.71
Market Price[3]				
High	$37.70	$43.50	$13.31	$21.00
Low	$16.66	$9.75	$5.69	$6.94
Year-End Close	$20.20	$37.63	$11.50	$7.38
Pro forma amounts assuming 1994 change in accounting principle is applied retroactively[2]				
Net Income (Loss)	$(22,347,765)	$59,184,008	$19,286,574	$(48,225,204)
Earnings (Loss) per Share—Basic[3]	$(0.90)	$2.79	$1.07	$(2.93)
Earnings (Loss) per Share—Diluted[3]	$(0.90)	$2.51	$1.07	$(2.93)
Assets				
Current Assets	$36,752,980	$41,872,879	$50,605,488	$35,246,431
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization	$628,304,060	$524,052,828	$392,986,589	$356,711,711
Total Assets	$671,684,833	$572,387,001	$454,299,414	$403,645,267
Liabilities				
Current Liabilities	$73,245,335	$64,324,771	$34,070,085	$31,415,054
Long-Term Debt	$258,197,128	$134,729,485	$239,068,423	$261,200,000
Total Liabilities	$359,032,113	$240,232,846	$283,895,297	$294,282,628
Stockholders' Equity	$312,652,720	$332,154,155	$170,404,117	$109,362,639
Number of Employees	209	181	173	203
Producing Wells				
Swift Operated	854	817	769	836
Outside Operated	381	711	788	917
Total Producing Wells	1,235	1,528	1,557	1,753
Wells Drilled (Gross)	53	70	27	75
Proved Reserves				
Natural Gas (Mcf)	324,912,125	418,613,976	329,959,750	352,400,835
Oil, NGL, & Condensate (barrels)	53,482,636	35,133,596	20,806,263	13,957,925
Total Proved Reserves (Mcf equivalent)	645,807,939	629,415,552	454,797,327	436,148,385
Production (Mcf equivalent)[4]	44,791,202	42,356,705	42,874,303	39,030,030
Average Sales Price				
Natural Gas (per Mcf)	$4.23	$4.24	$2.40	$2.08
Oil (per barrel)	$22.64	$29.35	$16.75	$11.86

[1] Additional 1994 Data: Income Before Cumulative Effect of Change in Accounting Principle–$3,725,671; Cumulative Effect of Change in Accounting Principle–$(16,772,698); Per Share Amounts–Basic–Income Before Cumulative Effect of Change in Accounting Principle–$0.51, Cumulative Effect of Change in Accounting Principle–$(2.29); Per Share Amounts–Diluted–Income Before Cumulative Effect of Change in Accounting Principle–$0.51, Cumulative Effect of Change in Accounting Principle–$(2.29).

[2] As of January 1, 1994, we changed our revenue recognition policy for earned interests. Accordingly, in 1994 to 1999, "Fees and Earned Interests" does not include earned interests revenues.

[3] 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; and (b) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share."

[4] Natural gas production for 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, and 2000 includes 1,148,862, 1,581,206, 1,358,375, 1,211,255, 1,156,361, 1,015,226, 866,232, 728,235, and 405,130 Mcf, respectively, delivered under our volumetric production payment agreement (see Note 1 to the Consolidated Financial Statements).

1997	1996	1995	1994[1]	1993	1992	1991
$69,015,189	$52,770,672	$22,527,892	$19,802,188	$15,535,671	$12,420,222	$8,361,771
$745,856	$937,238	$590,441	$701,528	$4,071,970	$2,716,277	$2,231,729
$2,395,406	$433,352	$212,329	$47,980	$201,584	$113,387	$192,694
$2,555,729	$2,156,764	$1,761,568	$1,072,535	$604,599	$515,931	$541,502
$74,712,180	$56,298,026	$25,092,230	$21,624,231	$20,413,824	$15,765,817	$11,327,696
$33,129,606	$28,785,783	$6,894,537	$4,837,829	$6,628,608	$4,687,519	$3,748,741
$22,310,189	$19,025,450	$4,912,512	$(13,047,027)	$4,896,253	$4,084,760	$2,512,815
$55,255,965	$37,102,578	$14,376,463	$10,394,514	$7,238,340	$6,349,080	$5,911,588
16,492,856	15,000,901	10,035,143	7,308,673	7,246,884	6,748,548	5,899,629
$1.35	$1.27	$0.49	$(1.79)	$0.68	$0.61	$0.43
$1.26	$1.25	$0.49	$(1.79)	$0.64	$0.61	$0.43
16,459,156	15,176,417	12,509,700	6,685,137	6,001,075	5,968,579	4,955,134
$9.69	$9.41	$7.46	$6.30	$9.08	$8.26	$7.80
$34.20	$28.86	$11.48	$10.35	$11.57	$7.85	$9.09
$16.93	$9.89	$7.05	$7.75	$7.14	$4.65	$4.34
$21.06	$27.16	$10.91	$8.86	$7.85	$7.55	$4.95
$22,310,189	$19,025,450	$4,912,512	$3,725,671	$4,322,478	$3,729,851	$2,950,245
$1.35	$1.27	$0.49	$0.51	$0.60	$0.55	$0.50
$1.26	$1.25	$0.49	$0.51	$0.57	$0.55	$0.50
$29,981,786	$101,619,478	$43,380,454	$39,208,418	$65,307,120	$30,830,173	$47,859,278
$301,312,847	$200,010,375	$125,217,872	$88,415,612	$89,656,577	$64,301,509	$47,655,917
$339,115,390	$310,375,264	$175,252,707	$135,672,743	$160,892,917	$100,243,469	$101,421,573
$28,517,664	$32,915,616	$40,133,269	$52,345,859	$55,565,437	$27,876,687	$50,851,447
$122,915,000	$115,000,000	$28,750,000	$28,750,000	$28,750,000	$0	$0
$179,714,470	$167,613,654	$81,906,742	$93,545,612	$106,427,203	$50,962,183	$62,761,217
$159,400,920	$142,761,610	$93,345,965	$42,127,131	$54,465,714	$49,281,286	$38,660,356
194	191	176	209	188	178	171
650	842	767	750	795	688	674
917	986	3,316	3,422	3,407	1,978	2,331
1,567	1,828	4,083	4,172	4,202	2,666	3,005
182	153	76	44	34	40	27
314,305,669	225,758,201	143,567,520	76,263,964	64,462,805	41,638,100	36,685,881
7,858,918	5,484,309	5,421,981	4,553,237	4,271,069	2,901,621	1,950,209
361,459,177	258,664,055	176,099,406	103,583,566	90,089,219	59,047,824	48,387,138
25,393,744	19,437,114	11,186,573	9,600,867	7,368,757	5,678,772	3,980,460
$2.68	$2.57	$1.77	$1.93	$1.96	$1.90	$1.58
$17.59	$19.82	$15.66	$14.35	$15.10	$17.19	$18.26

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

The following discussion should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

General

Over the last several years, we have emphasized adding reserves through drilling activity. We also add reserves through strategic purchases of producing properties when oil and gas prices are at lower levels and other market conditions are appropriate. During the past three years, we have used this flexible strategy of employing both drilling and acquisitions to add more reserves than we have depleted through production.

Proved Oil and Gas Reserves. At year-end 2001, our total proved reserves were 645.8 Bcfe with a PV-10 Value of $603.0 million. In 2001, our proved natural gas reserves decreased 93.7 Bcf, or 22%, while our proved oil reserves increased 18.3 MMBbl, or 52%, for a total equivalent increase of 16.4 Bcfe, or 3%. From 1999 to 2000, our proved natural gas reserves increased by 88.7 Bcf, or 27%, while our proved oil reserves increased by 14.3 MMBbl, or 69%, for a total equivalent increase of 174.6 Bcfe, or 38%. We added reserves from 2000 to 2001 through both our drilling activity and through purchases of minerals in place. Through drilling we added 105.8 Bcfe (17.4 Bcfe of which came from New Zealand) of proved reserves in 2001, 184.7 Bcfe (122.5 Bcfe of which came from New Zealand) in 2000, and 64.9 Bcfe in 1999. Through acquisitions we added 54.6 Bcfe of proved reserves in 2001, 39.7 Bcfe in 2000, and 20.1 Bcfe in 1999. At year-end 2001, 50% of our total proved reserves were proved developed, compared with 45% at year-end 2000 and 49% at year-end 1999.

While our total proved reserves quantities increased by 3% during 2001, the PV-10 Value of those reserves decreased 74%, due to much lower prices at year-end 2001 than at year-end 2000. Between those two year-ends, there was a 75% decrease in natural gas prices and a 25% decrease in oil prices. This decrease in prices resulted in 47.1 Bcfe of downward reserve revisions, solely attributed to the decrease in prices at year-end 2001. Gas prices were $2.51 per Mcf at year-end 2001, compared to $9.86 per Mcf at year-end 2000. Oil prices were $18.45 per Bbl at year-end 2001, compared to $24.62 a year earlier. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant 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. The year-end 2001 gas price of $2.51 was significantly lower than the average gas price of $4.23 we received during 2001. The year-end 2001 oil price of $18.45 per barrel was also lower than the average oil price of $22.64 we received in 2001. Had year-end reserves been calculated using the average 2001 prices we received, $22.64 for oil and $4.23 for gas, the PV-10 Value would have been approximately $947.8 million compared to the $603.0 million reported using year-end prices.

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 accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

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.

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, our management evaluates, among other factors, 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 income.

Full Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis for those countries with proved reserves.

The calculation of the Ceiling Test 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.

In 2001, as a result of low oil and gas prices at December 31, 2001, we reported a non-cash write-down on a before-tax basis of $98.9 million ($63.5 million after tax) on our domestic properties. We had no write-down on our New Zealand properties.

In addition, any unsuccessful exploratory well costs in countries in which there are no proved reserves are charged to expense as incurred. During the second quarter of 1999, we charged to income as additional depreciation, depletion, and amortization costs our portion of drilling costs associated with an unsuccessful exploratory well drilled by another operator in New Zealand. This charge was $290,000.

Because of the delineation of our 1999 Rimu discovery with two successful delineation wells drilled in 2000, proved reserves were recognized in New Zealand as of December 31, 2000.

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 significantly, even if only for a short period, it is possible that additional write-downs of oil and gas properties could occur in the future.

Price-Risk Management Activities. In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The statement establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138, was adopted by us on January 1, 2001.

We have a policy to use derivative instruments, mainly the buying of protection price floors, to protect against price declines in oil and gas prices. We elected not to designate our price floors for special hedge accounting treatment under SFAS No. 133, as amended. However, we have elected to use mark-to-market accounting treatment for our derivative contracts. Upon adoption of SFAS No. 133 on January 1, 2001, we recorded a net of taxes charge of $392,868, which is recorded as a Cumulative Effect of Change in Accounting Principle. During 2001 we recognized net gains of $1,173,094 relating to our derivative activities, with $16,784 in unrealized losses at year-end 2001. This activity is recorded in Price-risk management and other, net on the accompanying statements of income.

At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. These natural gas price floor contracts relate to the NYMEX contract months of February and March 2002 at an average price of $2.33 per MMBtu. The fair value of our open price floor contracts at December 31, 2001, totaled $296,000 and is included in Other current assets on the accompanying balance sheet.

Related-Party Transactions

We are the operator of a number of properties owned by our affiliated limited partnerships and joint ventures and, accordingly, charge these entities and third-party joint interest owners operating fees. The operating fees charged to the partnerships in 2001, 2000, and 1999 totaled approximately $925,000, $1,775,000, and $1,970,000, respectively. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $3,140,000, $4,465,000, and $4,000,000 in 2001, 2000, and 1999, respectively. In partnerships in which the limited partners have voted to sell their remaining properties and liquidate their limited partnerships, we are also reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately $2,360,000, $1,220,000, and $850,000 in 2001, 2000, and 1999, respectively.

Contractual Commitments and Obligations

Our contractual commitments for the next four years and thereafter are as follows:

	2002	2003	2004	2005	Thereafter	Total
Non-cancelable operating lease commitments	$1,393,095	$1,480,092	$1,492,268	$ 248,711	$ —	$ 4,614,166
Senior Notes due in August 2009	—	—	—	—	125,000,000	125,000,000
Credit Facility which expires in October 2005[1]	—	—	—	134,000,000	—	134,000,000
	$1,393,095	$1,480,092	$1,492,268	$134,248,711	$125,000,000	$263,614,166

[1]The repayment of the credit facility is based upon the balance at December 31, 2001. The amount borrowed under this facility has increased from 2001 year-end levels. This amount excludes $0.8 million of a standby letter of credit issued under this facility.

Liquidity and Capital Resources

During 2001, we relied both upon internally generated cash flows of $139.9 million and $123.4 million of additional borrowings from our bank credit facility to fund capital expenditures of $275.1 million. During 2000, we primarily used internally generated cash flows of $128.2 million to fund capital expenditures of $173.3 million, along with the remaining net proceeds from our third quarter 1999 issuance of Senior Notes and common stock.

Net Cash Provided by Operating Activities. In 2001, net cash provided by our operating activities increased by 9% to $139.9 million, as compared to $128.2 million in 2000 and $73.6 million in 1999. The 2001 increase of $11.7 million was primarily due to reductions in working capital as oil and gas sales receivables decreased in 2001 along with a reduction in interest expense of $3.3 million. These increases in cash flow were offset by an $8.0 million reduction of oil and gas sales, a $7.5 million increase in oil and gas production costs, and a $2.6 million increase in general and administrative expense. The 2000 increase of $54.6 million was primarily due to $80.2 million of additional oil and gas sales, partially offset by $12.2 million of increases in oil and gas production costs and interest expense.

Existing Credit Facilities. At December 31, 2001, we had $134.0 million in outstanding borrowings under our credit facility. Our credit facility at year-end 2001 consisted of a $250.0 million revolving line of credit with a $200.0 million borrowing base. The borrowing base is redetermined at least every six months. Our revolving credit facility includes, among other restrictions, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios) and limitations on incurring other debt. We are in compliance with the provisions of this agreement. The credit facility extends until October 2005. At December 31, 2000, we had $10.6 million in outstanding borrowings under this facility.

Subsequent to December 31, 2001, upon the closing of the New Zealand TAWN acquisition, the credit facility was increased to $300.0 million and the borrowing base became $275.0 million.

Working Capital. Our working capital decreased from a deficit of $22.5 million at December 31, 2000, to a deficit of $36.5 million at December 31, 2001. The decrease was primarily due to reductions in oil and gas sales receivables, as oil and gas prices were lower at year-end 2001, and an increase in payables to partnerships related to December 2001 oil and gas property sales.

Capital Expenditures. In 2001, our capital expenditures of approximately $275.1 million included:

Domestic Activities of $224.3 million as follows:

- $120.6 million, or 44%, on developmental drilling;
- $40.5 million, or 15%, for producing properties acquisitions, with approximately $32.6 million spent on the Lake Washington acquisition and the remainder for the purchase of property interests from partnerships managed by us;
- $36.4 million, or 13%, on exploratory drilling;
- $25.3 million, or 9%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- $1.1 million, or less than 1%, for fixed assets;
- $0.3 million on field compression facilities; and
- $0.1 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand Activities of $50.8 million as follows:

- $19.0 million, or 7%, on developmental drilling to further delineate the Rimu and Kauri areas;
- $17.9 million, or 7%, on the Rimu Production Station;
- $7.2 million, or 3%, for exploratory drilling in the Rimu and Kauri areas;
- $5.5 million, or 2%, on prospect costs, principally seismic and geological costs;
- $0.8 million, or less than 1%, on producing properties acquisition evaluation costs related to our TAWN acquisition; and
- $0.4 million for fixed assets, principally computers and office furniture and fixtures.

In 2001, we participated in drilling 40 development wells and 13 exploratory wells, of which 38 development wells and six exploratory wells were successes. Four of the development wells were drilled in New Zealand to delineate the Rimu and Kauri areas, two of which were successful. Two of the exploratory wells were drilled in New Zealand; one unsuccessful and one was temporarily abandoned. Of our $95.9 million of unproved property costs, $72.3 million relates to our inventory of developmental and exploratory acreage to sustain drilling activity for future growth, while the remaining $23.6 million pertains to the Rimu Production Station which will be reclassified to proved properties once it comes on-line near the end of the first quarter of 2002.

Capital expenditures for 2002 are estimated to be approximately $132.5 million. Approximately $39.8 million of the 2002 budget is allocated to domestic drilling, primarily in the Lake Washington area. In New Zealand, approximately $11.2 million of the 2002 budget is allocated to drilling, with another $8.7 million expected to be spent primarily for production facilities. In 2002, we anticipate drilling 20 development wells and 2 exploratory wells domestically, along with six development wells and one exploratory well in New Zealand. Approximately $54.6 million is targeted towards producing property acquisitions, the majority for the TAWN properties in New Zealand that closed in January 2002. Of the remainder $13.5 million will be used primarily for domestic leasehold, seismic, and geological costs, and $4.7 million is budgeted for such costs in New Zealand. This $132.5 million budget also excludes any producing property acquisitions that may arise in this low price environment and also excludes any property sales. Although we expect our 2002 total production to increase by 10% to 20% over 2001 due to the focus of our budget in the Lake Washington area and in New Zealand, we expect production to decline in our other core areas as no new drilling is currently budgeted to offset their natural production decline.

We believe that the anticipated internally generated cash flows for 2002, together with bank borrowings under our credit facility, will be sufficient to finance the costs associated with our currently budgeted 2002 capital expenditures. Should other producing property acquisitions activity become attractive in the current environment, the Company would intend to explore the use of debt and or equity offerings to fund such activity.

Our capital expenditures were approximately $173.3 million in 2000 and $78.1 million in 1999. During 1999, we used internally generated cash flows of $73.6 million to fund capital expenditures of $78.1 million. During 2000, we primarily used internally generated cash flows of $128.2 million to fund capital expenditures of $173.3 million, along with part of the remaining net proceeds from our third quarter 1999 issuance of Senior Notes and common stock. Our capital expenditures in 2000 included:

Domestic Activities of $157.9 million as follows:

- $90.3 million, or 52%, on developmental drilling;
- $33.4 million, or 19%, for producing properties acquisitions, approximately half of which was for the purchase of property interests from partnerships managed by us, with the other half purchased from a third party;
- $16.3 million, or 9%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- $15.5 million, or 9%, on exploratory drilling;
- $1.4 million, or 1%, for fixed assets;
- $0.8 million, or less than 1%, on gas processing plants in the Brookeland and Masters Creek areas; and

- $0.2 million on field compression facilities.

New Zealand Activities of $15.4 million as follows:

- $7.6 million, or 4%, on developmental drilling to further delineate the Rimu area;
- $4.5 million, or 3%, on prospect costs, principally seismic and geological costs;
- $2.1 million, or 1%, for exploratory drilling;
- $1.1 million, or 1%, on the initial stages of production facilities; and
- $0.1 million, or less than 1%, for fixed assets, principally a field office and warehouse.

In 2000, we participated in drilling 61 development wells and nine exploratory wells, of which 54 development wells and five exploratory wells were successes. Two of the development wells were drilled in New Zealand to delineate the Rimu area, both of which were successful.

Subsequent Events

TAWN Acquisition. Through our subsidiary, Swift Energy New Zealand Limited, we acquired Southern Petroleum Exploration Limited ("Southern NZ") in January 2002 for approximately $54.4 million in cash. 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. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 62.1 Bcfe, all of which were proved developed. This acquisition was accounted for by the purchase method of accounting. Upon the closing of this acquisition, our credit facility was increased to $300.0 million, and the borrowing base became $275.0 million.

In conjunction with the TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which includes our Rimu and Kauri areas, as well as a 25% interest in our Rimu Production Station. We do not know if Shell New Zealand will exercise this option. The option would be subject to numerous notifications, governmental approvals and consents if exercised. If the option is exercised, our credit facility would be reduced to $275.0 million and our borrowing base would be $250.0 million.

Antrim Acquisition. We purchased through our subsidiary, Swift Energy New Zealand Limited, all of the New Zealand assets owned by Antrim Oil and Gas Limited for 220,000 shares of Swift Energy Company common stock. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 5.7 Bcfe. This transaction closed in March 2002.

Results of Operations

Revenues. Our revenues in 2001 decreased by 4% compared to revenues in 2000 due primarily to decreases in oil prices.

Oil and gas sales revenues in 2001 decreased by 4%, or $8.0 million, from the level of those revenues for 2000 even though our net sales volumes in 2001 increased by 6%, or 2.4 Bcfe, over net sales volumes in 2000. Average prices received for oil decreased to $22.64 per Bbl in 2001 from $29.35 per Bbl in 2000. Average gas prices received decreased slightly to $4.23 per Mcf in 2001 from $4.24 per Mcf in 2000.

In 2001, our $8.0 million decrease in oil and gas sales resulted from:

- Price variances that had a $20.6 million unfavorable impact on sales, of which $20.5 million was attributable to the 23% decrease in average oil prices received and $0.1 million was attributable to the slight decrease in average gas prices received; and
- Volume variances that had a $12.6 million favorable impact on sales, with $17.1 million of increases coming from the 583,000 Bbl increase in oil sales volumes, offset somewhat by a decrease of $4.5 million from the 1.1 Bcf decrease in gas sales volumes.

Revenues in 2000 increased by 73% compared to 1999 revenues. In 2000, oil and gas sales revenues increased by 74%, or $80.2 million, over those revenues in 1999. In 2000, net sales volumes decreased by 1%, or 0.5 Bcfe, compared to net sales volumes in 1999. Average oil prices received went from $16.75 per Bbl in 1999 to $29.35 per Bbl in 2000, and average gas prices received increased from $2.40 per Mcf in 1999 to $4.24 per Mcf in 2000.

In 2000, our $80.2 million increase in oil and gas sales resulted from:

- Price variances that had an $81.7 million favorable impact on sales, of which $31.1 million was attributable to the 75% increase in average oil prices received and $50.6 million was attributable to the 77% increase in average gas prices received; and
- Volume variances that had a $1.5 million unfavorable impact on sales, with $1.6 million of decreases coming from the 93,000 Bbl decrease in oil sales volumes, partially offset by an increase of $0.1 million from the 40,000 Mcf increase in gas sales volumes.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes from our four domestic core areas and New Zealand:

	Revenues (in millions)		Net Sales Volume (Bcfe)	
Area	2001	2000	2001	2000
AWP Olmos	$ 56.1	$ 56.6	13.0	13.5
Brookeland	25.1	20.3	6.5	4.5
Lake Washington	4.6	—	1.2	—
Masters Creek	62.3	89.2	15.3	18.7
Other Domestic	31.3	23.0	8.3	5.7
Total Domestic	$ 179.4	$ 189.1	44.3	42.4
New Zealand	1.8	—	0.5	—
Total	$ 181.2	$ 189.1	44.8	42.4

Our 2001 drilling activity increased production in the Brookeland area and stabilized production in the AWP Olmos area, but did not prevent a decline in production in the Masters Creek area.

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

	Net Sales Volume			Average Sales Price	
	Oil (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	Gas (Mcf)
1999:					
First Qtr.	728	7.2	11.6	$10.87	$1.82
Second Qtr.	644	6.7	10.6	$15.25	$2.05
Third Qtr.	612	6.9	10.5	$18.46	$2.84
Fourth Qtr.	581	6.7	10.2	$23.99	$2.91
	2,565	27.5	42.9	$16.75	$2.40
2000:					
First Qtr.	653	6.6	10.6	$27.35	$2.93
Second Qtr.	650	6.9	10.8	$27.55	$3.99
Third Qtr.	591	7.0	10.5	$30.68	$4.39
Fourth Qtr.	578	7.0	10.5	$32.26	$5.55
	2,472	27.5	42.4	$29.35	$4.24
2001:					
First Qtr.	603	6.7	10.3	$27.63	$6.86
Second Qtr.	691	7.1	11.3	$26.05	$4.66
Third Qtr.	813	6.8	11.7	$23.76	$2.94
Fourth Qtr.	948	5.9	11.5	$16.02	$2.21
	3,055	26.5	44.8	$22.64	$4.23

Revenues from our oil and gas sales comprised 99% of total revenues for both 2001 and 2000 and 98% of total revenues for 1999. Natural gas production made up 59% of our production volumes in 2001, 65% in 2000, and 64% in 1999.

Costs and Expenses. Our general and administrative expenses, net in 2001 increased $2.6 million, or 47%, from the level of such expenses in 2000, while 2000 general and administrative expenses increased $1.1 million, or 24%, over 1999 levels. These increases reflect the increase in our corporate activities along with a reduction in reimbursement from partnerships we manage as these continue undergoing planned liquidation as voted upon by their limited partners. Our general and administrative expenses per Mcfe produced increased to $0.18 per Mcfe in 2001 from $0.13 per Mcfe in 2000 and $0.10 per Mcfe in 1999. The portion of supervision fees netted from general and administrative expenses was $3.1 million for 2001, $3.4 million for 2000, and $3.2 million for 1999.

Depreciation, depletion, and amortization of our assets, or DD&A, increased $11.7 million, or 25%, in 2001 from 2000, while 2000 DD&A increased $5.4 million, or 13%, from 1999 levels. In 2001, the increase was primarily due to additional dollars spent to add to our reserves and increased associated costs in an environment where demand for such services had increased compared to 2000, along with a 6% increase in production. In 2000, the increase was primarily due to the additional dollars spent to add to our reserves and associated costs in 2000 over 1999. Our DD&A rate per Mcfe of production was $1.33 in 2001, $1.13 in 2000, and $0.99 in 1999, reflecting variations in per unit cost of reserves additions.

Our production costs in 2001 increased $7.5 million, or 26%, over such expenses in 2000, while those expenses in 2000 increased $9.6 million, or 49%, over 1999 costs. Our production costs per Mcfe produced were $0.82 in 2001, $0.69 in 2000, and $0.46 in 1999. The portion of supervision fees netted from production costs was $3.1 million for 2001, $3.4 million for 2000, and $3.2 million for 1999. Approximately $1.7 million of the increase in production costs during 2001 was related to severance taxes. Severance taxes increased primarily from the expiration of certain specific well severance tax exemptions. The remainder of the increase reflected costs associated with new wells drilled and acquired and the related increase in costs in procuring such services in an environment where demand for such services has increased from the prior year.

While our production costs increased 49% in 2000, our oil and gas sales increased 74%. That increase in oil and gas sales had a direct impact on the increase in production costs, as severance taxes have a direct correlation to sales and were $4.9 million higher in 2000. Also, the increase in commodity prices brought increased demand and competition for field services that resulted in an increase in the cost of those services. Remedial well work and workover costs increased $1.2 million over 1999 levels. In the Masters Creek area, salt-water disposal charges, which increased $0.4 million over 1999 charges, increased as the volume of water associated with that production increased. Also in the Masters Creek area, production chemical costs increased $0.6 million as we began our scale inhibitor program in that area.

Interest expense on our Senior Notes issued in July 1999, including amortization of debt issuance costs, totaled $13.1 million in both 2001 and 2000 and $5.3 million in 1999. Interest expense on our Convertible Notes due 2006, including amortization of debt issuance costs, totaled $7.4 million in 2000 and $7.5 million in 1999. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5.8 million in 2001, $0.7 million in 2000 and $6.1 million in 1999. The total interest expense in 2001 was $18.9 million, of which $6.3 million was capitalized. The 2000 total interest expense was $21.2 million, of which $5.2 million was capitalized. The 1999 total interest expense was $18.9 million, of which $4.5 million was capitalized. We capitalize that portion of interest related to our exploration, partnership, and foreign business development activities. The decrease in total interest expense in 2001 was attributed to the conversion and extinguishment of our Convertible Notes in December 2000 and the increase in capitalized interest, partially offset by the increase in interest paid on our credit facility. The increase in interest expense in 2000 was attributed to the replacement of our bank borrowings in August 1999 with the Senior Notes that carry a higher interest rate.

In the fourth quarter of 2001, we took a domestic non-cash write-down of oil and gas properties, as discussed in Note 1 to the Consolidated Financial Statements. Lower prices for both oil and natural gas at December 31, 2001, necessitated a pre-tax domestic full-cost ceiling write-down of $98.9 million, or $63.5 million after tax. In addition to this domestic ceiling write-down, we also expensed $2.1 million of non-recurring charges in the fourth quarter of 2001 for certain delinquent accounts receivable, the majority of which is related to gas sold to Enron, and a write-off of debt issuance costs for a planned offering that was cancelled based upon market conditions following the events of September 11, 2001.

As discussed in Note 1 to the Consolidated Financial Statements, we adopted SFAS No. 133, amended by SFAS No. 137 and SFAS No. 138, on January 1, 2001. Our adoption of SFAS No. 133 resulted in a one-time net of taxes charge of $392,868, which is recorded as a Cumulative Effect of Change in Accounting Principle on our Consolidated Statement of Income.

In the fourth quarter of 2000, we recorded a $0.6 million non-recurring loss on the early extinguishment of debt (net of taxes), as discussed in Note 4 to the Consolidated Financial Statements. We called our Convertible Notes for redemption effective December 26, 2000. Holders of approximately $100.0 million of the Convertible Notes elected to convert their notes into shares of our common stock. Holders of the remaining $15.0 million of the Convertible Notes elected to redeem their notes for cash plus accrued interest. This cash redemption resulted in this non-recurring item.

Net Income (Loss). Our loss before extraordinary item and change in accounting principle in 2001 of $(22.0) million was 137% lower and Basic loss per share ("Basic EPS") before extraordinary item and change in accounting principle of $(0.89) was 132% lower than our 2000 net income of $59.8 million and Basic EPS of $2.82. These decreases reflected the effect of $101.0 million in non-recurring charges in 2001 as described above. The lower percentage decrease in Basic EPS reflects a 16% increase in weighted average shares outstanding in 2001, primarily due to the conversion of our Convertible Notes into 3.2 million shares of common stock in December 2000.

Our net loss for 2001 was $(22.3) million with a loss per share of $(0.90) per diluted share. Our net income for 2001, excluding non-recurring charges of $101.0 million as described above, totaled $42.5 million with EPS of $1.67 per diluted share. These amounts are lower than our 2000 net income of $59.8 million and EPS of $2.53 per diluted share, primarily due to significantly lower oil prices and overall increased costs.

Our income before extraordinary item in 2000 of $59.8 million was 210% higher and Basic EPS before extraordinary item of $2.82 was 164% higher than our 1999 net income of $19.3 million and Basic EPS of $1.07. These increases reflected the effect of the 75% increase in average oil prices received and 77% increase in average gas prices received. Oil and gas prices rose each quarter and resulted in quarterly sequential increases in earnings. The lower percentage increase in Basic EPS reflects an 18% increase in weighted average shares outstanding in 2000, primarily due to our third-quarter 1999 public sale of 4.6 million shares of common stock.

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 and 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 herein, 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 discussed above, and such volatility is expected to continue.

Our price risk program permits the utilization of agreements and financial instruments (such as futures, forward and options contracts, and swaps) 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* – In 2001 we elected not to designate our price floors for special hedge accounting treatment, and instead used mark-to-market accounting treatment. Our adoption of SFAS No. 133, as amended, is discussed in Note 1 to the Consolidated Financial Statements. Below is a summary of the utilization of price floors for the years ending December 31, 2001, 2000, and 1999.
  - During 2001 we recognized net gains of $1,173,094 related to our hedging activities, with $16,784 of losses unrealized at year-end 2001. This activity is recorded in Price-risk management and other, net on the accompanying statements of income. At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. These contracts relate to the NYMEX contract months of February and March 2002 at an average price of $2.33 per MMBtu. The fair value of our open contracts at December 31, 2001, totaled $296,000 and is included in the Other current assets account on the accompanying balance sheet.

    Prior to adopting SFAS No. 133 in 2001, costs and any benefits derived from price floors were recorded as a reduction or increase, as applicable, in oil and gas sales revenues for 2000 and 1999. The costs to purchase put options were amortized over the option periods in 2000 and 1999.
  - The costs related to 2000 hedging activities totaled approximately $1,083,000, with benefits of approximately $579,000 being received, resulting in a net cash outlay of approximately $504,000, or $0.012 per Mcfe. The costs related to the open contracts as of December 31, 2000, totaled approximately $823,000, which was our maximum exposure under those contracts. Those open contracts covering production for 2001 had a fair market value of approximately $209,000 at that date. Each of those contracts expired on or before March 31, 2001.
  - The costs related to 1999 hedging activities totaled approximately $909,000, with benefits of approximately $348,000 being received, resulting in a net cash outlay of approximately $561,000, or $0.013 per Mcfe. The costs related to the open contracts as of December 31, 1999, totaled approximately $98,000 and had a fair market value of $112,500.
- *Participating Collars* – During the fourth quarter of 1999, we entered into participating collars to hedge oil production through June 2000. Below is a summary of the collar arrangements for 2000. The participating collars were designated as hedges, and realized losses were recognized in oil and gas revenues when the associated production occurred.
  - We hedged 100,000 Bbls of oil per month for the months January through June 2000, with a floor price of $19.00 per Bbl and a ceiling price of $23.60 per Bbl, whereby we participate in 75% of any amount above the $23.60 ceiling price. These participating collars closed with our recording a loss of approximately $610,000, or $0.014 per Mcfe produced. There were no open participating collars at either year-end 2000 or 2001.

Interest Rate Risk. Our Senior Notes have a fixed interest rate, so consequently we are not exposed to cash flow or fair value risk from market interest rate changes on our Senior Notes. At December 31, 2001, we had $134.0 million borrowed under our credit facility, which is subject to floating rates and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 48 basis points and would impact 2002 cash flows by approximately $0.6 million based on this same level of borrowing.

Financial Instruments & Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2001 and 2000, and were determined based upon interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair value of our Senior Notes was $126.5 million at December 31, 2001, and $115.1 million at December 31, 2000. Our credit facility with the banks expires October 1, 2005. Our $125.0 million Senior Notes mature on August 1, 2009.

Report of Independent Public Accountants

To the Stockholders and Board of Directors of Swift Energy Company:

We have audited the accompanying consolidated balance sheets of Swift Energy Company (a Texas corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 financial position of Swift Energy Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Houston, Texas
February 18, 2002

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

	December 31, 2001	December 31, 2000
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,149,086	$ 1,986,932
Accounts receivable—		
Oil and gas sales	14,215,189	26,939,472
Associated limited partnerships and joint ventures	6,259,604	2,685,003
Joint interest owners	11,467,461	7,181,974
Other current assets	2,661,640	3,079,498
Total Current Assets	36,752,980	41,872,879
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	974,698,428	753,426,124
Unproved properties	95,943,163	55,512,872
	1,070,641,591	808,938,996
Furniture, fixtures, and other equipment	8,706,414	8,873,266
	1,079,348,005	817,812,262
Less — Accumulated depreciation, depletion, and amortization	(448,139,334)	(290,725,112)
	631,208,671	527,087,150
Other Assets:		
Deferred charges	3,723,182	3,426,972
	3,723,182	3,426,972
	$ 671,684,833	$ 572,387,001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 38,884,380	$ 54,977,397
Payable to associated limited partnerships	26,573,490	1,291,787
Undistributed oil and gas revenues	7,787,465	8,055,587
Total Current Liabilities	73,245,335	64,324,771
Long-Term Debt	258,197,128	134,729,485
Deferred Income Taxes	27,589,650	41,178,590
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 and 35,000,000 shares authorized, 25,634,598 and 25,452,148 shares issued, and 24,795,564 and 24,608,344 shares outstanding, respectively	256,346	254,521
Additional paid-in capital	296,172,820	293,396,723
Treasury stock held, at cost, 839,034 and 843,804 shares, respectively	(12,032,791)	(12,101,199)
Retained earnings	28,256,345	50,604,110
	312,652,720	332,154,155
	$ 671,684,833	$ 572,387,001

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2001	2000	1999
Revenues:			
Oil and gas sales	$181,184,635	$189,138,947	$ 108,898,696
Fees from limited partnerships and joint ventures	427,583	331,497	229,749
Interest income	49,281	1,339,386	833,204
Price-risk management and other, net	2,145,991	815,116	709,358
	183,807,490	191,624,946	110,671,007
Costs and Expenses:			
General and administrative, net of reimbursement	8,186,654	5,585,487	4,497,400
Depreciation, depletion, and amortization	59,502,040	47,771,393	42,348,901
Oil and gas production	36,719,609	29,220,315	19,645,740
Interest expense, net	12,627,022	15,968,405	14,442,815
Other expenses	2,102,251	—	—
Write-down of oil and gas properties	98,862,247	—	—
	217,999,823	98,545,600	80,934,856
Income (Loss) Before Income Taxes, Extraordinary Item and Change in Accounting Principle	(34,192,333)	93,079,346	29,736,151
Provision (Benefit) for Income Taxes	(12,237,436)	33,265,480	10,449,577
Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ (21,954,897)	$ 59,813,866	$ 19,286,574
Extraordinary Loss on Early Extinguishment of Debt (net of taxes)	—	629,858	—
Cumulative Effect of Change in Accounting Principle (net of taxes)	392,868	—	—
Net Income (Loss)	$ (22,347,765)	$ 59,184,008	$ 19,286,574
Per Share Amounts—			
Basic: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ (0.89)	$ 2.82	$ 1.07
Extraordinary Loss	—	(0.03)	—
Change in Accounting Principle	(0.01)	—	—
Net Income (Loss)	$ (0.90)	$ 2.79	$ 1.07
Diluted: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ (0.89)	$ 2.53	$ 1.07
Extraordinary Loss	—	(0.02)	—
Change in Accounting Principle	(0.01)	—	—
Net Income (Loss)	$ (0.90)	$ 2.51	$ 1.07
Weighted Average Shares Outstanding	24,732,099	21,244,684	18,050,106

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	Retained Earnings (Deficit)	Total
Balance, December 31, 1998	$ 169,725	$ 148,901,270	$ (11,841,884)	$ (27,866,472)	$ 109,362,639
Stock issued for benefit plans (90,738 shares)	224	(366,408)	978,956	—	612,772
Stock options exercised (65,477 shares)	655	461,102	—	—	461,757
Employee stock purchase plan (22,771 shares)	228	181,577	—	—	181,805
Public stock offering (4,600,000 shares)	46,000	41,915,310	—	—	41,961,310
Purchase of 246,500 shares as treasury stock	—	—	(1,462,740)	—	(1,462,740)
Net income	—	—	—	19,286,574	19,286,574
Balance, December 31, 1999	$ 216,832	$ 191,092,851	$ (12,325,668)	$ (8,579,898)	$ 170,404,117
Stock issued for benefit plans (46,632 shares)	310	297,060	224,469	—	521,839
Stock options exercised (543,450 shares)	5,434	4,316,446	—	—	4,321,880
Employee stock purchase plan (29,889 shares)	299	297,414	—	—	297,713
Subordinated notes conversion (3,164,644 shares)	31,646	97,392,952	—	—	97,424,598
Net income	—	—	—	59,184,008	59,184,008
Balance, December 31, 2000	$ 254,521	$ 293,396,723	$ (12,101,199)	$ 50,604,110	$ 332,154,155
Stock issued for benefit plans (11,945 shares)	72	354,973	68,408	—	423,453
Stock options exercised (152,915 shares)	1,529	1,942,634	—	—	1,944,163
Employee stock purchase plan (22,360 shares)	224	478,490	—	—	478,714
Net loss	—	—	—	(22,347,765)	(22,347,765)
Balance, December 31, 2001	$ 256,346	$ 296,172,820	$ (12,032,791)	$ 28,256,345	$ 312,652,720

[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, 2001	2000	1999
Cash Flows from Operating Activities:			
Net income (loss)	$ (22,347,765)	$ 59,184,008	$ 19,286,574
Adjustments to reconcile net income (loss) to net cash provided by operating activities—			
Depreciation, depletion, and amortization	59,502,040	47,771,393	42,348,901
Write-down of oil and gas properties	98,862,247	—	—
Deferred income taxes	(12,555,618)	33,413,626	10,435,115
Deferred revenue amortization related to production payment	—	(587,629)	(1,056,284)
Other	509,973	1,075,848	628,614
Change in assets and liabilities—			
(Increase) decrease in accounts receivable	16,207,377	(14,308,274)	(2,889,530)
Increase in accounts payable and accrued liabilities, excluding income taxes payable	12,984	1,601,042	4,850,036
Increase (decrease) in income taxes payable	(306,983)	47,213	—
Net Cash Provided by Operating Activities	139,884,255	128,197,227	73,603,426
Cash Flows from Investing Activities:			
Additions to property and equipment	(275,126,333)	(173,277,356)	(78,112,550)
Proceeds from the sale of property and equipment	9,274,440	3,844,375	4,531,935
Net cash received as operator of oil and gas properties	5,927,539	19,769,213	5,995,842
Net cash received (distributed) as operator of partnerships and joint ventures	(3,574,601)	2,674,593	(433,114)
Other	(534,898)	(1,329)	(131,135)
Net Cash Used in Investing Activities	(264,033,853)	(146,990,504)	(68,149,022)
Cash Flows from Financing Activities:			
Proceeds from (payments of) long-term debt	—	(15,203,000)	124,045,000
Net proceeds from (payments of) bank borrowings	123,400,000	10,600,000	(146,200,000)
Net proceeds from issuances of common stock	1,633,508	2,697,561	42,719,776
Purchase of treasury stock	—	—	(1,462,740)
Payments of debt issuance costs	(721,756)	—	(3,501,441)
Net Cash Provided by (Used in) Financing Activities	124,311,752	(1,905,439)	15,600,595
Net Increase (Decrease) in Cash and Cash Equivalents	$ 162,154	$ (20,698,716)	$ 21,054,999
Cash and Cash Equivalents at Beginning of Year	1,986,932	22,685,648	1,630,649
Cash and Cash Equivalents at End of Year	$ 2,149,086	$ 1,986,932	$ 22,685,648
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 12,207,205	$ 15,528,280	$ 8,618,020
Cash paid during year for income taxes	$ 441,926	$ —	$ —
Non-Cash Financing Activity:			
Conversion of convertible notes to common stock	$ —	$ 99,797,000	$ —

See accompanying 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 (Swift) 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 onshore oil and natural gas reserves in Texas and Louisiana, as well as onshore oil and natural gas reserves in New Zealand. Our investments in associated oil and gas partnerships and joint ventures 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 consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the consolidated financial statements. Certain reclassifications have been made to prior year amounts to conform to current year presentation.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

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. Under the full-cost method of accounting, such costs may be incurred both prior to or after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, equipment, and certain general and administrative costs directly associated with acquisition, exploration, and development activities. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. 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. The proceeds from the sale of oil and gas properties are generally treated as a reduction of oil and gas property costs. Fees from associated oil and gas exploration and development limited partnerships are credited to oil and gas property costs to the extent they do not represent reimbursement of general and administrative expenses currently charged to expense.

Future development, site restoration, and dismantlement and abandonment costs, net of salvage values, 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. The vast majority of our properties are onshore, and historically the salvage value of the tangible equipment offsets our site restoration and dismantlement and abandonment costs.

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, site restoration, and dismantlement and abandonment costs 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. This calculation is done on a country-by-country basis. All other equipment is depreciated by the straight-line method at rates based on the estimated useful lives of the property. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

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, among other factors, 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 income.

Full Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). 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.

In 2001, as a result of low oil and gas prices at December 31, 2001, we reported a non-cash write-down on a before-tax basis of $98.9 million ($63.5 million after tax) on our domestic properties. We had no write-down on our New Zealand properties.

In addition, any unsuccessful exploratory well costs in countries in which there are no proved reserves are charged to expense as incurred. During the second quarter of 1999, we charged to income as additional depreciation, depletion, and amortization costs our portion of drilling costs associated with an unsuccessful exploratory well drilled by another operator in New Zealand. This charge was $290,000.

Because of the delineation of our 1999 Rimu discovery with two successful delineation wells drilled in 2000, proved reserves were recognized in New Zealand as of December 31, 2000.

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 the Company's year-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional write-downs of oil and gas properties could occur in the future.

Oil and Gas Revenues. Oil and gas revenues are reported, as the product is delivered, using the entitlement method in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the differences are reported as deferred revenues. Natural gas balancing receivables are reported when our ownership share of production exceeds sales. As of December 31, 2001, we did not have any material natural gas imbalances.

Deferred Charges. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in November 1996 of our 6.25% Convertible Subordinated Notes (the "Convertible Notes"), with the public offering in August 1999 of our 10.25% Senior Subordinated Notes (the "Senior Notes"), and with our September 2001 extension of our bank credit facility were capitalized and are amortized over the life of each of the respective note offerings and credit facility. The Convertible Notes were called for redemption effective December 26, 2000, and the balance of their unamortized issuance costs at that time of $3,046,181 was either transferred to the common stock equity accounts ($2,643,476) for the portion of the Convertible Notes converted into common stock at the election of those note holders or was recorded, net of taxes, as Extraordinary Loss on Early Extinguishment of Debt ($402,705) for the portion of the Convertible Notes redeemed for cash. The Senior Notes mature on August 1, 2009, and the balance of their issuance costs at December 31, 2001, was $2,956,306, net of accumulated amortization of $545,135. The issuance costs associated with our revolving credit facility, which closed in September 2001, have been capitalized and are being amortized over the original life of the facility. The balance of revolving credit facility issuance costs at December 31, 2001, was $766,876, net of accumulated amortization of $513,573.

Limited Partnerships and Joint Ventures. We formed 88 limited partnerships between 1984 and 1995 to acquire interests in producing oil and gas properties and 13 partnerships between 1993 and 1998 to drill for oil and gas. In all of these partnerships, Swift paid for varying percentages of the capital or front-end costs and continuing costs of the partnerships and, in return, received differing percentage ownership interests in the partnerships, along with reimbursement of costs and/or payment of certain fees. At year-end 2001, we continue to serve as managing general partner of 71 of these various partnerships, and during fiscal 2001 approximately 2.9% of our total oil and gas sales was attributable to our interests in those partnerships.

During 1997 and 1998, eight drilling partnerships formed between 1979 and 1985 and 21 of the production purchase partnerships sold their properties and were dissolved, in each case following a vote of the investors in the particular partnerships approving such liquidations. Between 1999 and 2001, the investors in all but six of the remaining partnerships voted to sell the properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. We anticipate that the liquidation and dissolution of the additional 65 partnerships will be completed by the end of 2002. The remaining six partnerships will continue to operate until their limited partners vote otherwise.

Price-Risk Management Activities. In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The statement establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138, was adopted by us on January 1, 2001.

We have a policy to use derivative instruments, mainly the buying of protection price floors, to protect against price declines in oil and gas prices. We elected not to designate our price floors for special hedge accounting treatment under SFAS No. 133, as amended. However, we have elected to use mark-to-market accounting treatment for our derivative contracts. Upon adoption of SFAS No. 133 on January 1, 2001, we recorded a net of taxes charge of $392,868, which is recorded as a Cumulative Effect of Change in Accounting Principle. During 2001 we recognized net gains of $1,173,094 relating to our derivative activities, with $16,784 in unrealized losses at year-end 2001. This activity is recorded in Price-risk management and other, net on the accompanying statements of income.

At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. These natural gas price floor contracts relate to the NYMEX contract months of February and March 2002 at an average price of $2.33 per MMBtu. The fair value of our open price floor contracts at December 31, 2001, totaled $296,000 and is included in Other current assets on the accompanying balance sheets.

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 bases of assets and liabilities, given the provisions of the enacted tax laws.

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 monthly 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 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 2001, oil and gas sales to subsidiaries of Eastex Crude Company were $31.6 million, or 18.1% of oil and gas sales, while sales to subsidiaries of Enron were $18.2 million, or 10.4% of oil and gas sales. During 2000, oil and gas sales to subsidiaries of Eastex Crude Company were $47.4 million, or 25.7% of our oil and gas sales, while sales to subsidiaries of PG&E Energy Trading Corporation were $21.2 million, or 11.5% of oil and gas sales. During 1999, oil and gas sales to subsidiaries of Eastex Crude Company were $21.7 million, or 19.4% of our oil and gas sales. Beginning in December 2000, the subsidiaries of PG&E Energy Trading Corporation to which we made sales were sold to subsidiaries of El Paso Corporation. All receivables from PG&E were collected. During the fourth quarter of 2001, we wrote off $1.4 million due to uncollected receivables related to gas sold to Enron in November 2001. This amount is included in Other expenses on the Consolidated Statement of Income. We have discontinued sales of oil and gas to Enron and are selling that production to other purchasers.

Risk Factors. Our revenues, profitability and cash flow are substantially dependent upon the price of and demand for oil and gas. Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty, and a variety of additional factors beyond our control. We are also dependent upon the continued success of our domestic and New Zealand exploration and development programs. Other factors that could affect revenues, profitability, and cash flow include the inherent uncertainty in reserves estimates, our price-risk management activities, and the ability to replace reserves and finance our growth.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2001 and 2000, and were determined based upon interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair values of our Senior Notes were $126.5 million and $115.1 million at December 31, 2001 and 2000, respectively. The carrying value of our Senior Notes was $124.2 million and $124.1 million at December 31, 2001 and 2000, respectively.

New Accounting Pronouncements. In June 2001, the Financial Accounting Standards Board 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 entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated 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. We currently do not include dismantlement and abandonment costs in our depletion calculation as the vast majority of our properties are onshore and the salvage value of the tangible equipment offsets our dismantlement and abandonment costs. This standard will require us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. The standard is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. The Company is currently evaluating the effect of adopting Statement No. 143 on its financial statements and will adopt the statement on January 1, 2003.

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. The calculation of diluted earnings per share ("Diluted EPS") for 1999 and 2000 assumes conversion of our Convertible Notes as of the beginning of the respective periods and the elimination of the related after-tax interest expense. The calculation of diluted earnings per share for all periods assumes, as of the beginning of the period, exercise of stock options and warrants using the treasury stock method. The assumed conversion of our Convertible Notes applies only to the 2000 period since for the 1999 period they would have been antidilutive and since they were extinguished at year-end 2000. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2001 and 1999 periods.

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, 2001, 2000, and 1999:

	2001			2000			1999		
	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and Share Amounts	$(22,347,765)	24,732,099	$ (0.90)	$59,184,008	21,244,684	$ 2.79	$ 19,286,574	18,050,106	$ 1.07
Dilutive Securities:									
6.25% Convertible Notes	—	—		4,772,418	3,546,933		—	—	
Stock Options	—	—		—	713,112		—	42,365	
Diluted EPS:									
Net Income (Loss) and Assumed Share Conversions	$(22,347,765)	24,732,099	$ (0.90)	$63,956,426	25,504,729	$ 2.51	$ 19,286,574	18,092,471	$ 1.07

3. Provision for Income Taxes

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

	Year Ended December 31,		
	2001	2000	1999
Current	$ 114,611	$ (29,000)	$ (11,819)
Deferred	(12,352,047)	33,294,480	10,461,396
Total	$ (12,237,436)	$ 33,265,480	$ 10,449,577

There are differences between income taxes computed using the federal statutory rate (35% for 2001, 2000, and 1999) and our effective income tax rates (35.8%, 35.7%, and 35.1% for 2001, 2000, and 1999, respectively), primarily as the result of state income taxes, foreign income taxes and certain tax credits available to the Company. Foreign net income for SENZ for 2001 was $1,234,919. New Zealand's statutory rate and effective tax rate are 33%. Reconciliations of income taxes computed using the statutory rate to the effective income tax rates are as follows:

	2001	2000	1999
Income taxes computed at U.S. statutory rate	$ (11,967,317)	$ 32,577,772	$ 10,407,653
State tax provisions, net of federal benefits	(279,875)	775,850	(7,801)
Provision for foreign income tax	(24,698)	—	—
Other, net	34,454	(88,142)	49,725
Provision (benefit) for income taxes	$ (12,237,436)	$ 33,265,480	$ 10,449,577

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2001 and 2000, were as follows:

	2001	2000
Deferred tax assets:		
Alternative minimum tax credits	$ (1,979,399)	$ (1,979,399)
Net operating loss carry forward	(18,877,969)	(16,194,060)
Total deferred tax assets	$ (20,857,368)	$ (18,173,459)
Deferred tax liabilities:		
Domestic oil and gas properties	$ 47,539,564	$ 59,097,793
Foreign oil and gas properties	407,524	—
Other	482,513	254,256
Total deferred tax liabilities	$ 48,429,601	$ 59,352,049
Net deferred tax liability	$ 27,572,233	$ 41,178,590

As of December 31, 2001, we had $52.7 million of net operating loss carry forwards, which expire as follows: $29.0 million, $20.1 million, $3.0 million and $0.6 million in 2013, 2014, 2015 and 2016, respectively.

We did not record any valuation allowances against deferred tax assets at December 31, 2001 and 2000.

At December 31, 2001, we had alternative minimum tax credits of $1,979,399 that carry forward indefinitely and are available to reduce future regular tax liability to the extent they exceed the related tentative minimum tax otherwise due.

4. Long-Term Debt

Our long-term debt as of December 31, 2001 and 2000, is as follows:

	2001	2000
Bank Borrowings	$ 134,000,000	$ 10,600,000
Senior Notes	124,197,128	124,129,485
Long-Term Debt	$ 258,197,128	$ 134,729,485

Bank Borrowings. At December 31, 2001, we had outstanding borrowings of $134.0 million under our $250.0 million credit facility with a syndicate of nine banks which has a borrowing base of $200 million. At December 31, 2000, we had borrowings of $10.6 million under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.75% at December 31, 2001) 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. Of the $134.0 million borrowed at December 31, 2001, $130.0 million was borrowed at the LIBOR rate plus applicable margin, which averaged 3.64%. Of the $10.6 million borrowed at December 31, 2000, $5.0 million was borrowed at the LIBOR rate plus applicable margin (which averaged 7.89% at December 31, 2000).

Upon closing of the New Zealand TAWN acquisition in January 2002, our credit facility increased to $300.0 million and the borrowing base increased to $275.0 million. For further information on this acquisition, see Footnote 9 "Subsequent Events."

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), requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. Effective September 28, 2001, the credit facility was extended until October 1, 2005.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5,833,564 in 2001, $654,936 in 2000, and $6,107,270 in 1999.

Convertible Notes. In November 1996, we sold $115.0 million of 6.25% Convertible Subordinated Notes due 2006. The Convertible Notes were unsecured and convertible into Swift common stock at the option of the holders at an adjusted conversion price of $31.534 per share. Interest on the notes was payable semiannually, on May 15 and November 15. On December 11, 2000, we called for the redemption of our Convertible Notes effective December 26, 2000, at 103.75% of their principal amount. Holders of approximately $100.0 million of the Convertible Notes elected to convert their notes into 3,164,644 shares of our common stock. Holders of the remaining $15.0 million of the Convertible Notes elected to redeem their notes for cash plus accrued interest. This cash redemption resulted in our recognizing an Extraordinary Loss on the Early Extinguishment of Debt (net of taxes) of $0.6 million, or $1.0 million before taxes.

Interest expense on the Convertible Notes, including amortization of debt issuance costs, totaled $7,426,599 in 2000 and $7,569,361 in 1999.

Senior Notes. Our Senior Notes consist of $125.0 million of 10.25% Senior Subordinated Notes due 2009. The Senior Notes were issued at 99.236% of the principal amount on August 4, 1999, and will mature on August 1, 2009. The Senior Notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank debt. Interest on the Senior Notes is payable semiannually, on February 1 and August 1, and commenced with the first payment on February 1, 2000. On or after August 1, 2004, the Senior Notes are redeemable for cash at the option of Swift, with certain restrictions, at 105.125% of principal, declining to 100% in 2007. In addition, prior to August 1, 2002, we may redeem up to 33.33% of the Senior Notes with the proceeds of qualified offerings of our equity at 110.25% of the principal amount of the Senior Notes, together with accrued and unpaid interest. Upon certain changes in control of Swift, each holder of Senior Notes will have the right to require us to repurchase the Senior Notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase.

Interest expense on the Senior Notes, including amortization of debt issuance costs and discount, totaled $13,123,052 in 2001, $13,092,127 in 2000, and $5,303,266 in 1999.

Debt Maturities. Our bank borrowings are due in October 2005, and our Senior Notes are due in August 2009.

5. Commitments and Contingencies

Total rental and lease expenses were $1,322,611 in 2001, $1,255,474 in 2000, and $1,272,497 in 1999. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $1,393,095 for 2002, $1,480,092 for 2003, $1,492,268 for 2004, and $248,711 for 2005. 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.

As of December 31, 2001, we were the managing general partner of 71 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 the financial position or results of operations of Swift.

6. Stockholders' Equity

Common Stock. During the third quarter of 1999, we issued 4.6 million shares of common stock at a price of $9.75 per share. Gross proceeds from this offering were $44,850,000, with issuance costs of $2,888,690.

In December 2000, the holders of approximately $100.0 million of our Convertible Notes converted such notes into 3,164,644 shares of our common stock, which resulted in an increase in our common stock capital accounts of approximately $97.4 million.

Stock-Based Compensation Plans. We have two current stock option plans, 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 plan. In addition, we have an employee stock purchase plan. No further grants will be made under the 1990 non-qualified 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 may be granted options to purchase shares of common stock. 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 expire 10 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 option price is credited to common stock and additional paid-in capital.

The employee stock purchase plan provides eligible employees the opportunity to acquire shares of Swift 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 22,360 shares at a price of $21.41 in 2001, 29,889 shares at a price range of $8.40 to $10.57 in 2000, and 22,771 shares at a price range of $5.21 to $11.00 in 1999. The estimated weighted average fair value of shares issued under this plan, as determined using the Black-Scholes option-pricing model, was $8.19 in 2001, $4.25 in 2000, and $4.74 in 1999. As of December 31, 2001, 362,428 shares remained available for issuance under this plan. There are no charges or credits to income in connection with this plan.

We account for our stock option plans under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." As all options were issued at a price equal to market price, no compensation expense has been recognized. 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 (loss) and earnings (loss) per share would have been adjusted to the following pro forma amounts:

			2000	1999
Net Income (Loss):	As Reported	$(22,347,765)	$59,184,008	$19,286,574
	Pro Forma	$(26,632,624)	$56,531,665	$16,869,122
Basic EPS:	As Reported	$(0.90)	$2.79	$1.07
	Pro Forma	$(1.08)	$2.66	$0.93
Diluted EPS:	As Reported	$(0.90)	$2.51	$1.07
	Pro Forma	$(1.08)	$2.40	$0.93

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years.

The following is a summary of our stock options as of December 31, 2001, 2000, and 1999:

	2001		2000		1999	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,076,593	$ 11.70	2,148,511	$ 9.08	2,266,146	$ 9.03
Options granted	747,073	$ 31.51	645,944	$ 16.88	25,000	$ 12.50
Options canceled	(31,247)	$ 14.09	(174,412)	$ 8.71	(77,158)	$ 8.95
Options exercised	(152,915)	$ 8.69	(543,450)	$ 8.48	(65,477)	$ 8.55
Options outstanding, end of period	2,639,504	$ 17.44	2,076,593	$ 11.70	2,148,511	$ 9.08
Options exercisable, end of period	1,181,141	$ 11.49	897,711	$ 9.35	1,280,156	$ 8.87
Options available for future grant, end of period	1,155,057		181,235		950,735	
Estimated weighted average fair value per share of options granted during the year	$20.68		$10.90		$7.10	

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 2001, 2000, and 1999, respectively: no dividend yield; expected volatility factors of 46.9%, 46.7%, and 44.2%; risk-free interest rates of 5.24%, 6.61%, and 5.60%; and expected lives of 7.3, 6.7, and 7.5 years. The following table summarizes information about stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/01	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/01	Wtd. Avg. Exercise Price
$ 5.00 to $16.99	1,592,597	5.7	$ 9.50	1,012,907	$ 9.20
$17.00 to $28.99	280,439	6.1	$ 23.25	153,785	$ 24.23
$29.00 to $41.00	766,468	9.1	$ 31.84	14,449	$ 36.69
$ 5.00 to $41.00	2,639,504	6.8	$ 17.44	1,181,141	$ 11.49

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, and service is recognized after the ESOP effective date. 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. Compensation expense is reported when such shares are released to employees. The plan may also acquire Swift common stock purchased at fair market value. The ESOP can borrow money from Swift to buy Swift stock. Benefits will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2001, 2000 and 1999, all of the ESOP compensation was earned.

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 contribution to the 401(k) savings plan totaled $558,000, $483,000, and $474,000 for the years ended December 31, 2001, 2000, and 1999, respectively. The contribution in 2001 was made all in common stock, while the 2000 and 1999 contributions were made half in common stock and half in cash. The shares of common stock contributed to the 401(k) savings plan totaled 28,798, 7,175, and 21,810 shares for the 2001, 2000, and 1999 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, 2001, 839,034 shares remain in treasury (net of 88,740 shares used to fund ESOP and 401(k) contributions) with a total cost of $12,032,791 and are included in "Treasury stock held, at cost" on the balance sheet.

Shareholder Rights Plan. In August 1997, the board of directors declared a dividend of one preferred share purchase right on each outstanding share of Swift 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 are the operator of a number of properties owned by our affiliated limited partnerships and joint ventures and, accordingly, charge these entities and third-party joint interest owners operating fees. The operating fees charged to the partnerships in 2001, 2000, and 1999 totaled approximately $925,000, $1,775,000, and $1,970,000, respectively. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $3,140,000, $4,465,000, and $4,000,000 in 2001, 2000, and 1999, respectively. In partnerships in which the limited partners have voted to sell their remaining properties and liquidate their limited partnerships, we are also reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately $2,360,000, $1,220,000, and $850,000 in 2001, 2000, and 1999, respectively.

8. Foreign Activities

New Zealand

Swift Operated Permits. Our activity in New Zealand began in 1995 with the issuance of the first of two petroleum exploration permits. After surrendering a portion of our permit acreage in 1998, combining the two permits and expanding the permit acreage in 1999, and relinquishing 50% of the acreage in 2001 as we extended our petroleum exploration permit, our permit 38719 as of year-end 2001 covered approximately 50,300 acres in the Taranaki Basin of New Zealand's north island, with all but 12,800 acres onshore. At December 31, 2001, we had a 90% working interest in this permit and had fulfilled all current obligations under this permit.

In late 1999, we completed our first exploratory well on this permit, the Rimu-A1, and a production test was performed. During the second half of 2000, we drilled and successfully tested two development wells, the Rimu-B1 and the Rimu-B2. In 2001 we drilled and tested three more Rimu development wells, the Rimu-A2, Rimu-A3 and Rimu-B3. The Rimu-A3 was successful; the Rimu-A2 and Rimu-B3 were dry. Early in 2002, the Rimu-A2 was sidetracked to the Tariki sand and is currently awaiting completion. The Rimu-B3 was also sidetracked in early 2002 and again was unsuccessful. In 2001, we also drilled the Kauri-A1 exploratory well, the Kauri-A2 development well, and the Kauri-B1 exploratory well. In the Kauri-A-1 we tested the Upper Tariki sands and still have further zones to test. The Kauri-A2 well successfully tested the Manutahi sands. The Kauri-B1 was drilled approximately 1.75 miles to the southeast of the Kauri-A pad and targeted the Manutahi sands. This well was plugged and abandoned in 2001. Our portion of the drilling, completion, and testing costs incurred on the wells within our permits during 2001 was approximately $26.0 million. Our portion of prospect costs on our permits during 2001 was approximately $5.1 million, which included obtaining 2-D seismic data in the last half of the year for the Rata prospect. We incurred $22.5 million on the production facilities that we expect to be commissioned near the end of the first quarter of 2002.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we would earn a 25% participating interest in petroleum exploration permit 38730 containing approximately 48,900 acres. In May 2001, Fletcher relinquished their interest in the permit, and we then assumed 100% working interest in such permit by means of committing to an acceptable work plan. Such plan required us to acquire a minimum of 30 kilometers of new 2D seismic data, which we completed in 2001. Rather than commit to drill a new well in 2002 as the work plan called for, we surrendered this project in February 2002.

Non-Operated Permits. In 1998, we entered into agreements for a 25% working interest in an exploration permit, permit 38712, held by Marabella Enterprises Ltd., a subsidiary of Bligh Oil & Minerals, an Australian company, and a 7.5% working interest held by Antrim Oil and Gas Limited, a Canadian company, in a second permit, permit 38716, operated by Marabella. In turn, Bligh and Antrim each became 5% working interest owners in our permit 38719. Unsuccessful exploratory wells were drilled on these two permits, and we charged $0.4 million against earnings in 1998 and $0.3 million in 1999. All of the acreage on the permit 38712 was surrendered in 2000. The exploratory well on permit 38716 has been temporarily abandoned pending a further evaluation. It is currently anticipated that this well will be re-entered and side-tracked to target a location to the west of the initial well. A five-year extension was granted on permit 38716 in 2001 upon the surrender of 50% of the acreage.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we will earn a 20% participating interest in petroleum exploration permit 38718 containing approximately 57,400 acres. In January 2001, the operator temporarily abandoned the Tuihu #1 exploratory well on permit 38718 pending further analysis. The permit now contains approximately 28,700 acres after a scheduled surrender during December 2000.

Costs Incurred. During 2001, our costs incurred in New Zealand totaled $54.5 million, including $25.7 million for drilling, $5.5 million for prospect costs, $22.5 million for production facilities, and $0.8 million in evaluation costs for the acquisition of the TAWN assets, which closed in January 2002. These costs also included $0.6 million of costs incurred on permits operated by others: $0.2 million of drilling costs and $0.4 million of prospect costs. As of December 31, 2001, our investment in New Zealand totaled approximately $84.4 million. As we have recorded proved undeveloped reserves relating to our successful drilling activities, $45.5 million of our investment costs has been included in the proved properties portion of oil and gas properties and $38.8 million has been included as unproved properties at the end of 2001. Our development strategy includes having Rimu/Kauri production on line for oil and gas sales in New Zealand near the end of the first quarter of 2002.

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. We retain a minimum 6% net profits interest from the sale of hydrocarbon products from the fields. The value of our net profits interest depends upon either the successful development of production from the fields by others or their sale of the fields.

9. Subsequent Events

TAWN Acquisition. Through our subsidiary, Swift Energy New Zealand Limited, we acquired Southern Petroleum Exploration Limited ("Southern NZ") in January 2002 for approximately $54.4 million in cash. 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 properties are collectively called "TAWN," an acronym for the four fields that comprise the property: Tariki, Ahuroa, Waihapa and Ngaere. This acquisition was accounted for by the purchase method of accounting. Upon the closing of the New Zealand acquisition, our credit facility was increased to $300.0 million and the borrowing base became $275.0 million.

In conjunction with the TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which includes our Rimu and Kauri areas, as well as a 25% interest in our Rimu Production Station. We do not know if Shell New Zealand will exercise this option. The option would be subject to numerous notifications, governmental approvals and consents if exercised. If the option is exercised, our credit facility would be reduced to $275.0 million and our borrowing base would be $250.0 million.

Antrim Acquisition. We purchased through our subsidiary, Swift Energy New Zealand Limited, all of the New Zealand assets owned by Antrim Oil and Gas Limited for 220,000 shares of Swift Energy Company common stock. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716. This transaction closed in March 2002 (unaudited).

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, 2001:			
Proved oil and gas properties	$ 974,698,428	$ 929,172,460	$ 45,525,968
Unproved oil and gas properties	95,943,163	57,096,694	38,846,469
	1,070,641,591	986,269,154	84,372,437
Accumulated depreciation, depletion, and amortization	(442,337,531)	(442,166,052)	(171,479)
Net capitalized costs	$ 628,304,060	$ 544,103,102	$ 84,200,958
December 31, 2000:			
Proved oil and gas properties	$ 753,426,124	$ 732,265,674	$ 21,160,450
Unproved oil and gas properties	55,512,872	46,833,274	8,679,598
	808,938,996	779,098,948	29,840,048
Accumulated depreciation, depletion, and amortization	(284,886,168)	(284,886,168)	—
Net capitalized costs	$ 524,052,828	$ 494,212,780	$ 29,840,048

Of the $57,096,694 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2001, excluded from the amortizable base, $26,707,313 was incurred in 2001, $9,545,964 was incurred in 2000, $5,640,587 was incurred in 1999, and $15,202,830 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. In response to market conditions in 1998, we decreased our 1999 drilling expenditures when compared to prior years, which, when coupled with the $15.3 million of leasehold properties acquired in the Brookeland and Masters Creek areas in 1998, may extend the evaluation time frame of such costs. Consequently, in response to market conditions, we have decreased our 2002 drilling expenditures as well.

Of the $38,846,469 of net New Zealand unproved property costs at December 31, 2001, excluded from the amortizable base, $30,383,713 was incurred in 2001, $5,013,539 was incurred in 2000, $907,972 was incurred in 1999, and $2,541,245 was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there, with seven wells planned for drilling in 2002. We expect to complete our evaluation of current unevaluated costs over the next two to three years. Upon the startup of the Rimu Production Station near the end of the first quarter of 2002, $23.6 million of these unproved property costs will be moved to the proved properties classification and will begin being depreciated.

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

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 41,286,539	$ 40,491,203	$ 795,336
Lease acquisitions [1]	31,225,493	25,688,068	5,537,425
Exploration	41,981,536	35,944,405	6,037,131
Development	132,246,713	112,597,856	19,648,857
Total acquisition, exploration, and development [2]	$ 246,740,281	$ 214,721,532	$ 32,018,749
Processing plants	$ 23,331,095	$ 817,454	$ 22,513,641
Field compression facilities	319,703	319,703	—
Total plants and facilities	$ 23,650,798	$ 1,137,157	$ 22,513,641
Total costs incurred	$ 270,391,079	$ 215,858,689	$ 54,532,390

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 34,191,883	$ 34,191,883	$ —
Lease acquisitions [1]	20,842,103	16,315,749	4,526,354
Exploration	20,150,834	18,524,883	1,625,951
Development	104,083,409	93,931,500	10,151,909
Total acquisition, exploration, and development [2]	$ 179,268,229	$ 162,964,015	$ 16,304,214
Processing plants	$ 1,819,464	$ 755,119	$ 1,064,345
Field compression facilities	203,789	203,789	—
Total plants and facilities	$ 2,023,253	$ 958,908	$ 1,064,345
Total costs incurred	$ 181,291,482	$ 163,922,923	$ 17,368,559

	Year Ended December 31, 1999		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 18,526,939	$ 18,526,939	$ —
Lease acquisitions [1]	10,382,672	9,251,658	1,131,014
Exploration	11,019,430	5,101,330	5,918,100
Development	39,891,868	39,891,868	—
Total acquisition, exploration, and development [2]	$ 79,820,909	$ 72,771,795	$ 7,049,114
Processing plants	$ 1,607,559	$ 1,607,559	$ —
Field compression facilities	171,535	171,535	—
Total plants and facilities	$ 1,779,094	$ 1,779,094	$ —
Total costs incurred	$ 81,600,003	$ 74,550,889	$ 7,049,114

[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 2001, 2000, and 1999 were $13,308,843, $16,791,834, and $14,389,680, respectively.

[2] Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $11,600,000, $10,300,000, and $8,500,000 in 2001, 2000, and 1999, respectively. In addition, total includes $6,256,222, $5,043,206, and $4,142,098 in 2001, 2000, and 1999, respectively, of capitalized interest on unproved properties.

Results of Operations. New Zealand operations began in 2001 while all our oil and gas operations in 2000 and 1999 were domestic. The following table sets forth results of our oil and gas operations:

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Oil and gas sales	$ 181,184,635	$179,360,844	$ 1,823,791
Oil and gas production costs	(36,719,609)	(36,554,418)	(165,191)
Depreciation and depletion	(58,589,116)	(58,417,637)	(171,479)
Write-down of oil and gas properties	(98,862,247)	(98,862,247)	—
	(12,986,337)	(14,473,458)	1,487,121
Provision (benefit) for income taxes	(4,647,810)	(5,138,560)	490,750
Results of producing activities	$ (8,338,527)	$ (9,334,898)	$ 996,371
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.31	$ 1.32	$ 0.34

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Oil and gas sales	$ 189,138,947	$189,138,947	$ —
Oil and gas production costs	(29,220,315)	(29,220,315)	—
Depreciation and depletion	(46,849,819)	(46,849,819)	—
	113,068,813	113,068,813	—
Provision (benefit) for income taxes	40,365,566	40,365,566	—
Results of producing activities	$ 72,703,247	$ 72,703,247	$ —
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.11	$ 1.11	$ —

	Year Ended December 31, 1999		
	Total	Domestic	New Zealand
Oil and gas sales	$ 108,898,696	$108,898,696	$ —
Oil and gas production costs	(19,645,740)	(19,645,740)	—
Depreciation and depletion	(41,410,106)	(41,410,106)	—
	47,842,850	47,842,850	—
Provision (benefit) for income taxes	16,792,840	16,792,840	—
Results of producing activities	$ 31,050,010	$ 31,050,010	$ —
Amortization per physical unit of production (equivalent Mcf of gas)	$ 0.97	$ 0.97	$ —

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's summary report dated February 14, 2002, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2001, 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, 1998[1]	352,400,835	13,957,925	352,400,835	13,957,925	—	—
Revisions of previous estimates[2]	(31,189,450)	2,058,725	(31,189,450)	2,058,725	—	—
Purchases of minerals in place	9,159,780	1,822,858	9,159,780	1,822,858	—	—
Sales of minerals in place	(3,762,799)	(260,287)	(3,762,799)	(260,287)	—	—
Extensions, discoveries, and other additions	30,107,908	5,791,966	30,107,908	5,791,966	—	—
Production[3]	(26,756,524)	(2,564,924)	(26,756,524)	(2,564,924)	—	—
Proved reserves as of December 31, 1999[1]	329,959,750	20,806,263	329,959,750	20,806,263	—	—
Revisions of previous estimates[2]	(4,300,787)	(455,606)	(4,300,787)	(455,606)	—	—
Purchases of minerals in place	26,567,925	2,196,547	26,567,925	2,196,547	—	—
Sales of minerals in place	(363,262)	(76,288)	(363,262)	(76,288)	—	—
Extensions, discoveries, and other additions	93,869,841	15,134,694	38,556,364	3,943,807	55,313,477	11,190,887
Production[3]	(27,119,491)	(2,472,014)	(27,119,491)	(2,472,014)	—	—
Proved reserves as of December 31, 2000	418,613,976	35,133,596	363,300,499	23,942,709	55,313,477	11,190,887
Revisions of previous estimates[2]	(122,127,541)	5,621,556	(101,693,477)	8,460,690	(20,434,064)	(2,839,134)
Purchases of minerals in place	10,038,803	7,430,591	10,038,803	7,430,591	—	—
Sales of minerals in place	(7,508,064)	(555,586)	(7,508,064)	(555,586)	—	—
Extensions, discoveries, and other additions	52,353,909	8,907,852	50,810,697	6,257,441	1,543,212	2,650,411
Production[3]	(26,458,958)	(3,055,373)	(26,458,958)	(2,971,112)	—	(84,261)
Proved reserves as of December 31, 2001[4]	324,912,125	53,482,636	288,489,500	42,564,733	36,422,625	10,917,903
Proved developed reserves:						
December 31, 1998	197,105,963	7,142,566	197,105,963	7,142,566	—	—
December 31, 1999	174,046,096	8,437,299	174,046,096	8,437,299	—	—
December 31, 2000	215,169,833	10,980,196	215,169,833	10,980,196	—	—
December 31, 2001[4]	181,651,578	23,759,574	167,401,736	20,393,142	14,249,842	3,366,432

[1]Proved reserves exclude quantities subject to our volumetric production payment agreement, which expired with the last required delivery of volumes in October 2000.

[2]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 and natural gas prices at each year-end. Proved reserves, as of December 31, 2001, were based upon prices in effect at year-end. The weighted average of such year-end prices for total, domestic, and New Zealand were $2.51, $2.68, and $1.18 per Mcf of natural gas and $18.45, $18.51, and $18.25 per barrel of oil, respectively. This compares to $9.86, $11.25, and $0.71 per Mcf and $24.62, $25.50, and $22.30 per barrel as of December 31, 2000, for total, domestic, and New Zealand, respectively.

[3]Natural gas production for 1999 and 2000 excludes 728,235 and 405,130 Mcf, respectively, delivered under our volumetric production payment agreement.

[4]We acquired 62.1 Bcfe and 5.7 Bcfe from the TAWN and Antrim acquisitions, respectively, in New Zealand. These reserves estimates at December 31, 2001, are not included in the above table. The TAWN reserves were all proved developed while the Antrim reserves were 34% proved developed.

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, 2001		
	Total	Domestic	New Zealand
Future gross revenues	$ 1,706,475,138	$ 1,485,480,927	$ 220,994,211
Future production costs	(483,588,857)	(436,141,429)	(47,447,428)
Future development costs	(198,172,628)	(185,347,628)	(12,825,000)
Future net cash flows before income taxes	1,024,713,653	863,991,870	160,721,783
Future income taxes	(261,635,331)	(208,726,729)	(52,908,602)
Future net cash flows after income taxes	763,078,322	655,265,141	107,813,181
Discount at 10% per annum	(308,520,417)	(274,882,174)	(33,638,243)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 454,557,905	$ 380,382,967	$ 74,174,938

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Future gross revenues	$ 4,995,951,799	$ 4,737,560,630	$ 258,391,169
Future production costs	(817,127,348)	(807,436,139)	(9,691,209)
Future development costs	(204,620,116)	(180,320,116)	(24,300,000)
Future net cash flows before income taxes	3,974,204,335	3,749,804,375	224,399,960
Future income taxes	(1,321,061,952)	(1,243,731,594)	(77,330,358)
Future net cash flows after income taxes	2,653,142,383	2,506,072,781	147,069,602
Discount at 10% per annum	(1,075,183,917)	(1,017,995,158)	(57,188,759)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,577,958,466	$ 1,488,077,623	$ 89,880,843

	Year Ended December 31, 1999		
	Total	Domestic	New Zealand
Future gross revenues	$ 1,371,541,850	$ 1,371,541,850	$ —
Future production costs	(353,594,258)	(353,594,258)	—
Future development costs	(156,738,446)	(156,738,446)	—
Future net cash flows before income taxes	861,209,146	861,209,146	—
Future income taxes	(226,725,033)	(226,725,033)	—
Future net cash flows after income taxes	634,484,113	634,484,113	—
Discount at 10% per annum	(195,540,279)	(195,540,279)	—
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 438,943,834	$ 438,943,834	$ —

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 certain abandonment costs 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. 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 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 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,		
	2001	2000	1999
Beginning balance	$ 1,577,958,466	$ 438,943,834	$ 290,273,103
Revisions to reserves proved in prior years—			
Net changes in prices, production costs, and future development costs	(1,692,627,074)	1,523,487,598	123,447,890
Net changes due to revisions in quantity estimates	(93,669,181)	(36,102,814)	(23,746,974)
Accretion of discount	231,325,481	56,405,451	34,078,501
Other	(204,768,815)	(220,119,873)	2,032,696
Total revisions	(1,759,739,589)	1,323,670,362	135,812,113
New field discoveries and extensions, net of future production and development costs	110,213,160	359,265,150	102,582,467
Purchases of minerals in place	39,544,163	160,240,785	39,282,292
Sales of minerals in place	(50,131,970)	(598,021)	(5,360,428)
Sales of oil and gas produced, net of production costs	(144,262,145)	(159,331,003)	(88,196,672)
Previously estimated development costs incurred	94,107,760	65,953,028	39,149,732
Net change in income taxes	586,868,060	(610,185,669)	(74,598,773)
Net change in standardized measure of discounted future net cash flows	(1,123,400,561)	1,139,014,632	148,670,731
Ending balance	$ 454,557,905	$1,577,958,466	$ 438,943,834

Quarterly Results. The following table presents summarized quarterly financial information for the years ended December 31, 2000 and 2001:

	Revenues	Income/(Loss) Before Income Taxes	Income/(Loss) Before Extraordinary Item and Change in Accounting Principle	Net Income/(Loss)	Basic EPS Income/ (Loss) Before Extraordinary Item and Change in Accounting Principle	Diluted EPS Income/(Loss) Before Extraordinary Item and Change in Accounting Principle	Basic EPS Net Income/ (Loss)	Diluted EPS Net Income/ (Loss)
2000:								
First Quarter	$ 37,747,645	$ 14,919,044	$ 9,589,828	$ 9,589,828	$ 0.46	$ 0.43	$ 0.46	$ 0.43
Second Quarter	46,127,375	22,218,358	14,213,274	14,213,274	0.68	0.61	0.68	0.61
Third Quarter	49,525,166	24,748,163	15,832,348	15,832,348	0.74	0.66	0.74	0.66
Fourth Quarter	58,224,760	31,193,781	20,178,416	19,548,558	0.93	0.82	0.90	0.80
Total	$ 191,624,946	$ 93,079,346	$ 59,813,866	$ 59,184,008	$ 2.82	$ 2.53	$ 2.79	$ 2.51
2001:								
First Quarter	$ 62,392,014	$ 35,513,130	$ 22,719,653	$ 22,326,785	$ 0.92	$ 0.89	$ 0.91	$ 0.88
Second Quarter	52,303,265	23,408,900	14,972,946	14,972,946	0.61	0.59	0.61	0.59
Third Quarter	41,244,583	11,607,563	7,420,090	7,420,090	0.30	0.29	0.30	0.29
Fourth Quarter	27,867,628	(104,721,926)	(67,067,586)	(67,067,586)	(2.71)	(2.71)	(2.71)	(2.71)
Total	$ 183,807,490	$ (34,192,333)	$ (21,954,897)	$ (22,347,765)	$ (0.89)	$ (0.89)	$ (0.90)	$ (0.90)

PART I

Items 1 and 2. Business and Properties

See pages 59 and 60 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 onshore oil and natural gas reserves in Texas and Louisiana and onshore oil and natural gas reserves in New Zealand. The Company was founded in 1979 and is headquartered in Houston, Texas. As of December 31, 2001, we had interests in 1,235 wells located domestically in five states, in federal offshore waters, and in New Zealand. We operated 854 of these wells representing 95% our proved reserves. At year-end 2001, we had estimated proved reserves of 645.8 Bcfe, of which approximately 50% was natural gas and 50% was proved developed. Our proved reserves are concentrated 53% in Texas, 28% in Louisiana, and 16% in New Zealand.

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

Area	Location	% of Year-End 2001 Proved Reserves	% of 2001 Production
AWP Olmos	South Texas	32%	29%
Brookeland	East Texas	9%	15%
Lake Washington	South Louisiana	11%	3%
Masters Creek	Central Louisiana	16%	34%
New Zealand	New Zealand	16%	1%
% of Total		84%	82%

The AWP Olmos and Lake Washington areas and New Zealand are characterized by long-lived reserves that we expect to be steadily produced over a long period of time. The Brookeland and Masters Creek areas are characterized by shorter-lived reserves with high initial rates of production that decline rapidly. We believe these shorter-lived reserves complement our long-lived reserves. We focus on drilling the long-lived properties during periods of decreasing commodity prices, while the shorter-lived properties provide additional drillable projects in periods of rising commodity prices. Based on 2001 year-end domestic proved reserves and 2001 domestic production, our average domestic reserve life was 12.3 years. Based on a report by an independent engineering firm, prepared as part of the mining license application process, the Rimu/Kauri development area is estimated to have a 25-30 year economic life.

We purchased interests in the Brookeland and Masters Creek areas from Sonat Exploration Company in the third quarter of 1998 for approximately $85.8 million in cash. Of this purchase price, $55.5 million was spent for producing properties, $15.0 million for 20% interests in two natural gas processing plants, and $15.3 million for leasehold properties. This acquisition generated two new core areas. Then in late December 1999, we purchased additional working interests in the Masters Creek area from Dominion Reserves, Inc., for approximately $14.0 million in cash and purchased additional working interests in the S. Burr Ferry portion of the Masters Creek area from Union Pacific for approximately $1.9 million. We expect to use our operating expertise in this geological trend to continue to successfully develop and exploit these properties.

In the first quarter of 2001, we purchased interests in the Lake Washington field from Elysium Energy, LLC, for approximately $30.5 million in cash. This acquisition created the newest core area for the Company.

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 addition, we seek to enhance the results of our drilling and production efforts through the implementation of advanced technologies. For 1999, in response to lower oil and gas prices in 1998 that continued in the first half of 1999, we decreased our capital expenditures budget to $54.2 million, of which $36.0 million was targeted for drilling, $31.3 million for development drilling, and $4.7 million for exploratory drilling. The remaining $18.2 million was targeted principally for leasehold, seismic, and geological costs of prospects. After oil and gas prices rebounded in the second half of the year, we increased our capital expenditures during the fourth quarter. We funded the $78.1 million of capital expenditures spent in 1999 primarily through our internally generated cash flows of $73.6 million, while the remainder was funded with net proceeds from our third quarter 1999 public offering of common stock and Senior Notes that remained after paying off our bank debt.

For 2000, in response to the strengthening of oil and gas prices and the resulting increase in cash flows generated from these commodity prices, we increased our capital expenditures to $173.3 million, of which $105.8 million was targeted for drilling in the United States, with $90.3 million for development drilling and $15.5 million for exploratory drilling. We spent $9.7 million in drilling to further delineate our Rimu discovery in New Zealand. Additionally, $33.4 million was spent for producing property acquisitions. The remaining $24.4 million was used principally for leasehold, seismic, and geological costs of prospects. We funded the $173.3 million of capital expenditures in 2000 primarily through our internally generated cash flows of $128.2 million, while the remainder was funded with net proceeds from our third quarter 1999 public offering of common stock and Senior Notes that remained after paying off our bank debt and funding capital expenditures in 1999.

During 2001, as oil and gas prices continued to rise early in the year and stayed strong through the first half of the year, our cash flow generated due to these commodity prices increased as well. As a result of this cash flow and our continued efforts in New Zealand, along with the opportunity to acquire the Lake Washington assets, we increased our capital expenditures to $275.1 million. Of this amount, $157.0 million was spent on drilling in the United States, with $120.6 million for development drilling and $36.4 million for exploratory drilling. We spent $26.2 million on drilling in New Zealand, with $19.0 million on development drilling and $7.2 million on exploratory drilling. We also spent $17.9 million constructing a gas processing plant in New Zealand and $40.5 million for domestic producing property acquisitions, primarily for the Lake Washington acquisition. The remaining $33.5 million was spent primarily on leasehold, seismic and geological costs of prospects, both in the United States and New Zealand. During 2001, we relied upon internally generated cash flows of $139.9 million to partially fund our capital expenditures; the remainder was funded with increases in borrowings under our bank credit facility.

Due to falling oil and gas prices in the second half of 2001 and continuing into 2002, we have again reduced our 2002 capital expenditures budget and intend on focusing on low risk development drilling on long-lived reserve properties. Therefore, our 2002 drilling will focus in Lake Washington and on developing our Rimu and Kauri areas in New Zealand. We anticipate spending approximately $132.5 million in 2002 for capital expenditures, with approximately $50.9 million of this amount for drilling activity. The TAWN acquisition, which closed in January 2002, accounted for $54.4 million of this budget. This $132.5 million budget also excludes any property acquisition that may present itself in this low price environment and also excludes any property sales.

We have increased our proved reserves from 258.7 Bcfe at year-end 1996 to 645.8 Bcfe at year-end 2001, which has resulted in the replacement of 302% of our production during the same five-year period. In 2001, we increased our proved reserves by 3%, which replaced 136% of our 2001 production. Our five-year average reserves replacement costs were $1.26 per Mcfe. Our 2001 production increased by 6% in relation to 2000 production. We have increased our production from 19.4 Bcfe at year-end 1996 to 44.8 Bcfe at year-end 2001. Primarily due to increased production, along with strong 2001 commodity prices, this has resulted in average annual growth in net cash provided by operating activities of 30% per year from year-end 1996 to year-end 2001.

Domestic Properties

AWP Olmos Area. As of December 31, 2001, we owned approximately 28,562 net acres in the AWP Olmos area. We have extensive expertise and a long history of experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 74% gas. At year-end 2001, we owned interests in 496 wells and were the operator of 492 wells in this area producing gas from the Olmos sand formation at a depth of approximately 10,000 to 11,500 feet. We own nearly 100% of the working interests in all wells in which we are the operator.

In 2001, we drilled 11 development wells in the AWP Olmos area, all of which were successful. At year-end 2001, we had 122 proved undeveloped locations. Also in 2001, we purchased interests in the AWP Olmos area from partnerships we manage. Our planned 2002 capital expenditures in this area will focus on performing fracture extensions and installing coiled tubing velocity strings.

Brookeland Area. As of December 31, 2001, we owned drilling and production rights in 127,703 gross acres (79,874 net acres) and 15,000 fee mineral acres in this area, which contains substantial proved undeveloped reserves. This area was part of the acquisition from Sonat in 1998 and is located in East Texas near the border of Louisiana in Jasper and Newton counties. It primarily contains horizontal wells producing from the Austin Chalk formation. The reserves are approximately 60% oil and natural gas liquids. In 2001, we drilled or participated in the drilling of 11 development wells there, all of which were successful. At year-end 2001, we had 17 proved undeveloped locations in this area.

Lake Washington Field. As of December 31, 2001, we owned drilling and production rights in 13,595 net acres in the Lake Washington field. This area is located in Plaquemines Parish in South Louisiana. The reserves are approximately 95% oil and natural gas liquids. We acquired interests in the Lake Washington field in March 2001. This field produces oil from multiple Miocene sands ranging in depth from less than 2,000 feet to greater than 10,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its inception. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 25 producing wells is gathered from four platforms located in water depths from 6 to 11 feet, with drilling and workover operations performed with barge rigs. In 2001, four development wells and one exploratory well were drilled in the area, all of which were successful. At year-end 2001, we had 29 proved undeveloped locations in this field. Our planned 2002 capital expenditures in this area are approximately $25.0 million and include 20 development wells and two exploratory wells.

Masters Creek Area. As of December 31, 2001, we owned drilling and production rights in 194,212 gross acres (149,400 net acres) and 141,000 fee mineral acres in this area, which contains substantial proved undeveloped reserves. This area was also part of the acquisition from Sonat in 1998. It 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 74% oil and natural gas liquids. In 2001, we drilled nine development wells in the area, all of which were successful. At year-end 2001, we had 18 proved undeveloped locations in the area.

Exploration and Development Drilling Activities

We pursue a "controlled risk" approach to exploratory and development drilling, focusing our domestic activities on specific regions in which our technical staff has considerable experience and which are located close to known producing horizons. In our foreign operations, we chose New Zealand based on its hydrocarbon potential combined with its political and economic attributes. We seek to minimize our exploration risk by investing in multiple prospects, farming out interests to third parties, using advanced technologies, and drilling in diverse types of geological formations, often in areas with multiple objectives. We use basin studies to analyze targeted formations based on their potential size, risk profile, and economic characteristics.

In 1991, we began an intensive effort to develop an inventory of exploration and development drilling prospects, identifying drilling locations through integrated geological and geophysical studies of our undeveloped acreage and other prospects. As a result, we added 64.9 Bcfe of proved reserves through drilling in 1999, 184.7 Bcfe in 2000 (122.5 Bcfe from New Zealand), and 105.8 Bcfe in 2001 (17.4 Bcfe from New Zealand). The 2001 additions were a result of our development success rate, as 38 of 40 development wells drilled were successful, while 6 of 13 exploratory wells were successful.

Our development strategy is designed to maximize the value and productivity of our existing properties through development drilling and recovery methods, enhancing production results through improved field production techniques, lowering production costs, and applying our technical expertise and resources to exploit producing properties efficiently. We utilize various recovery techniques, which include employing water flooding and acid treatments, fracturing reservoir rock through the injection of high-pressure fluid, and inserting coiled tubing velocity strings to enhance and maintain gas flow. We believe that the application of fracturing technology and coiled tubing over the years has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos area. In 2001, however, as the exploration and production industry rushed to get new projects into production to take advantage of the commodity prices in the first half of the year, service sector capacity was constrained and the costs of services skyrocketed. This, along with increased severance and ad-valorem taxes, caused our production costs to increase in 2001.

Our exploration and development activities are conducted by our staff of professionals, including reservoir engineers, geologists, geophysicists, petrophysicists, landmen, and drilling and production engineers. We believe that one of the keys to our success has been our team approach, which integrates multiple disciplines to maximize efficient utilization of information leading to drillable projects.

We have increasingly used advanced seismic technology to enhance the results of our drilling and production efforts, including 2-D and 3-D seismic analysis, amplitude versus offset studies, and detailed formation depletion studies. We have a number of computer workstations from which seismic data is analyzed and enhanced with advanced software programs, including Landmark, Geographix, and SMT workstations. As a result, we have maintained internal seismic expertise and have compiled an extensive database.

During 1997, we completed our first international seismic acquisition program in two key areas in New Zealand. In the Rimu prospect, we acquired 30 kilometers (18.7 miles) of 2-D cross-swath data, as well as 14.5 kilometers (9 miles) of 2-D line data in the Tawa prospect, complementing existing 2-D seismic coverage. Following our 1999 Rimu discovery, we conducted a second seismic acquisition in March 2000 in which we obtained 42 kilometers (26 miles) of 2-D lines to more fully identify the extent of the Rimu structure. We also obtained approximately 72.5 kilometers (45 miles) of data from a number of 2-D transitional zone seismic lines tied to existing marine and land seismic grids in order to study the Kauri structure to the southeast of Rimu. During 2001, we acquired approximately 30 kilometers (18.7 miles) of 2-D line data in PEP 38730, in which we own a 100% working interest. Further processing and analysis of the data will continue in 2002.

Also in 1997, we acquired 21 miles of 2-D data in the AWP Olmos area in south Texas and 51 miles of data in the Fayette County portion of the Giddings area. Two more prospects in the North Louisiana Salt Basin were shot in the form of 2-D swaths of approximately 16 miles each. During 1998, we performed two additional 2-D acquisitions in Fayette County, Texas. In all our current and future projects, we have an on-going program in which we license existing seismic data for reprocessing with available new technologies. In certain areas we also complement existing data with proprietary seismic data designed for specific geologic targets. This results in an integrated approach to exploration (multidiscipline data analysis and interpretation) that helped identify a number of our exploration prospects for 2001.

In addition to operation, development and exploration activities in the AWP Olmos, Brookeland, Lake Washington and Masters Creek areas, we are currently pursuing development and exploration activities in the following emerging growth areas and in New Zealand.

The Frio Trend. Swift Energy has been focusing on the deep sands of the Frio formation (10,000 to 16,000 feet) in an area that straddles the border of Kenedy County and Willacy County in the southern tip of Texas and is identified as Garcia Ranch. Retaining a 65% working interest, Swift had two discoveries in the area in 2001, one in the Rome prospect in Willacy County at a depth of 16,388 feet, and the other in the Siena prospect in Kenedy County at a depth of 16,300 feet.

The Wilcox Sands. The Company had three discoveries in the Wilcox sands during 2001, two of which were located in Goliad County, Texas: the Nita prospect drilled to a depth of approximately 15,000 feet and the Brandon prospect drilled to a depth of about 13,000 feet. Swift's working interests in the two wells are 73% and 60%, respectively. The third well, in which the Company has a 25% working interest, was in the Falcon Ridge prospect in Zapata County, Texas.

The Woodbine Formation. Swift drilled one well to the Woodbine formation during 2001—in the Lion prospect in San Jacinto County, Texas, down to a depth of 16,300 feet. Although hydrocarbon-bearing intervals were found, the well was determined to be noncommercial.

The Miocene Sands. Swift successfully drilled its first exploratory well in the Miocene sands in its new Lake Washington area in Plaquemines Parish, Louisiana—to a depth of 3,348 feet with a retained interest of 100%. This area has substantial exploration and development potential, with sands extending from shallow depths down to 10,000 feet or more. Current plans are to drill another exploratory well in the area during 2002.

Also in Plaquemines Parish, about 50 miles north of the Lake Washington area, is the Delacroix area where the Company has also been developing prospects for both shallow and deep horizons in the Miocene sands. The first well in this area, in the Grand Lake prospect, was drilled to a depth of 18,571 feet early in 2002 and was temporarily abandoned for a possible future sidetrack well.

New Zealand. We operate permit 38719 with a 90% working interest. After working several years and analyzing extensive seismic data, we commenced drilling a successful exploratory well, the Rimu-A1, in July 1999. In 2000, we drilled two successful Rimu development wells. Our permit contains 50,300 gross acres, including 12,800 adjacent offshore acres. In 2001, we drilled three development wells to further delineate our Rimu area, one of which was successful. We also drilled two exploratory wells in the Kauri area, one still being evaluated and the other one unsuccessful. In addition, we drilled one successful development well in our Kauri area and participated in a non-operated exploratory well in another permit area that was temporarily abandoned in 2001.

The Tawa prospect is located northwest of the Rimu and Kauri areas in the same permit. Its main targets are the Tikorangi limestone, the Kauri sandstone, and the Tariki sandstone. Consisting of a combination of structural and stratigraphic traps, this prospect was developed based upon Swift's analysis of existing three-dimensional seismic data plus two-dimensional seismic data acquired during Company surveys in 1997 and 2000.

The Matai prospect, located on the southeast flank of the Tawa prospect also in permit 37819, will target the Moki sandstone. It was identified based upon the analysis of the two-dimensional seismic data Swift acquired in 2000.

The following table sets forth the results of our drilling activities during the three years ended December 31, 2001:

		Gross Wells				Net Wells			
Year	Type of Well	Total	Producing	Dry	Temporarily Abandoned	Total	Producing	Dry	Temporarily Abandoned
1999	Exploratory–Domestic	3	1	2	—	1.5	0.3	1.2	—
	Development–Domestic	22	19	3	—	10.7	9.4	1.3	—
	Exploratory–New Zealand	2	1	—	1	1.0	0.9	—	0.1
2000	Exploratory–Domestic	9	5	4	—	6.2	3.4	2.8	—
	Development–Domestic	59	52	7	—	42.4	37.1	5.3	—
	Development–New Zealand	2	2	—	—	1.8	1.8	—	—
2001	Exploratory–Domestic	11	6	5	—	6.2	4.0	2.2	—
	Development–Domestic	36	36	—	—	29.5	29.5	—	—
	Exploratory–New Zealand	2	—	1	1	1.1	—	0.9	0.2
	Development–New Zealand	4	2	2	—	3.6	1.8	1.8	—

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 gas. The fees for these activities paid to us in 2001 ranged from $200 to $2,216 per well per month and totaled $6.2 million.

Marketing of Production

We typically sell our oil and gas production at market prices near the wellhead, although in some cases it must be gathered and delivered to a central point. Gas production is sold in the spot market on a monthly basis, while we sell our oil production at prevailing market prices. We do not refine any oil we produce. Two oil or gas purchasers accounted for 10% or more of our total revenues during the year ended December 31, 2001, with those purchasers accounting for approximately 29% of revenues in the aggregate. For the year ended December 31, 2000, two purchasers accounted for approximately 37% of our total revenues. 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 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, both affiliates of El Paso Merchant Energy, 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. Additionally, the gas processed and transported under these agreements may be sold to El Paso based upon current natural gas prices.

Our oil production from the Brookeland and Masters Creek areas is sold to various purchasers at prevailing market prices. Our 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 for sales to various purchasers at prevailing market prices. Our 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 into the international market at prices tied to the Asia Petroleum Price Index Tapis posting, less the cost of storage, trucking, and transportation.

Our gas production from our TAWN fields, which we acquired and closed on in January 2002, is sold under a long-term contract with Contact Energy. Upon commissioning of the Rimu Production Station, our gas production from the Rimu field will be sold to Genesis Power Ltd. under a long-term contract.

Swift natural gas liquids production from the TAWN fields is sold to RockGas under long-term contracts tied to New Zealand's domestic natural gas liquids market. Upon commissioning of the Rimu Production Station, our natural gas liquids from the Rimu Field also will be sold to RockGas.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and gas production for the three-year period ended December 31, 2001. "Net" production is production that is owned by us either directly or indirectly through partnerships or joint venture interests and is produced to our interest after deducting royalty, limited partner, and other similar interests.

	Year Ended December 31,		
	2001	2000	1999
Net Sales Volume:			
Oil (Bbls)[1]	3,055,374	2,472,014	2,564,924
Gas (Mcf)[2]	26,458,958	27,524,621	27,484,759
Gas equivalents (Mcfe)	44,791,202	42,356,705	42,874,303
Average Sales Price:			
Oil (per Bbl)[1]	$ 22.64	$ 29.35	$ 16.75
Gas (per Mcf)	$ 4.23	$ 4.24	$ 2.40
Average Production Cost (per Mcfe)	$ 0.82	$ 0.69	$ 0.46

[1]Oil production for 2001 includes New Zealand production of 84,261 barrels, at an average price per barrel of $21.64.

[2]Natural gas production for 2000 and 1999 includes 405,130 and 728,235 Mcf, respectively, delivered under the volumetric production payment agreement pursuant to which we were obligated to deliver certain monthly quantities of natural gas (see Note 1 to the Consolidated Financial Statements). Under the volumetric production payment entered into in 1992, we delivered the last remaining commitment of gas in October 2000, when such agreement expired.

Acquisition Activities

We use a disciplined, market-driven approach to acquisitions. Generally we seek to acquire properties with the potential for additional reserves and production through development and exploration efforts. In 142 transactions from 1979 to 2001, we have acquired approximately $631.5 million of producing oil and gas properties on behalf of ourselves and our co-investors. We acquired, for our own account, approximately $275.0 million of producing properties, with original proved reserves estimated at 394.3 Bcfe. Our producing property acquisition expenditures in the past three years were $41.3 million in 2001, $34.2 million in 2000, and $18.5 million in 1999. Our acquisition costs have averaged $0.82 per Mcfe over this three-year period. Our acquisition cost in 2001 averaged $0.76 per Mcfe. During 2002, we intend to actively look for acquisition opportunities in this environment of lower commodity prices.

Foreign Activities

New Zealand

Swift Operated Permits. Our activity in New Zealand began in 1995 with the issuance of the first of two petroleum exploration permits. After surrendering a portion of our permit acreage in 1998, combining the two permits and expanding the permit acreage in 1999, and relinquishing 50% of the acreage in 2001 as we extended our petroleum exploration permit, our permit 38719 as of year-end 2001 covered approximately 50,300 acres in the Taranaki Basin of New Zealand's north island, with all but 12,800 acres onshore. At December 31, 2001, we had a 90% working interest in this permit and had fulfilled all current obligations under this permit.

In late 1999, we completed our first exploratory well on this permit, the Rimu-A1, and a production test was performed. During the second half of 2000, we drilled and successfully tested two development wells, the Rimu-B1 and the Rimu-B2. In 2001 we drilled and tested three more Rimu development wells, the Rimu-A2, Rimu-A3 and Rimu-B3. The Rimu-A3 was successful; the Rimu-A2 and Rimu-B3 were dry. Early in 2002, the Rimu-A2 was sidetracked to the Tariki sand and is currently awaiting completion. The Rimu-B3 was also sidetracked in early 2002 and again was unsuccessful. In 2001, we also drilled the Kauri-A1 exploratory well, the Kauri-A2 development well, and the Kauri-B1 exploratory well. In the Kauri-A-1 we tested the Upper Tariki sands and still have further zones to test. The Kauri-A2 well successfully tested the Manutahi sands. The Kauri-B1 was drilled approximately 1.75 miles to the southeast of the Kauri-A pad and targeted the Manutahi sands. This well was plugged and abandoned in 2001. Our portion of the drilling, completion, and testing costs incurred on the wells within our permits during 2001 was approximately $26.0 million. Our portion of prospect costs on our permits during 2001 was approximately $5.1 million, which included obtaining 2-D seismic data in the last half of the year for the Rata prospect. We incurred $22.5 million on the production facilities that we expect to be commissioned near the end of the first quarter of 2002. In 2002, we plan to drill six development wells in the Rimu and Kauri areas, to participate in a non-operated exploratory well in another permit area, and to complete production facilities with $24.6 million budgeted to be spent. This compares to $54.5 million spent in 2001 and $17.4 million spent in 2000.

Our New Zealand production is subject to a royalty which is a hybrid consisting of a 5% ad valorem royalty, or "AVR," and a 20% accounting profits royalty, or "APR." Until a mining permit is obtained for our producing area, only the AVR will apply to all production, and thereafter the royalty will be the greater of the AVR or APR, calculated on an annual basis. The AVR is based on net sales revenues. The APR is based on the excess of net sales revenues over allowable deductions, which deductions include production, capital, and indirect costs, but not interest or income tax expense or "head office costs" above 2.5% of other costs. Operating losses and capital costs may be carried forward to subsequent periods until fully utilized.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we would earn a 25% participating interest in petroleum exploration permit 38730 containing approximately 48,900 acres. In May 2001, Fletcher relinquished their interest in the permit, and we then assumed 100% working interest in such permit by means of committing to an acceptable work plan. Such plan required us to acquire a minimum of 30 kilometers of new 2D seismic data, which we completed in 2001. Rather than commit to drill a new well in 2002 as the work plan called for, we surrendered this project in February 2002.

Non-Operated Permits. In 1998, we entered into agreements for a 25% working interest in an exploration permit,

permit 38712, held by Marabella Enterprises Ltd., a subsidiary of Bligh Oil & Minerals, an Australian company, and a 7.5% working interest held by Antrim Oil and Gas Limited, a Canadian company in a second permit, permit 38716, operated by Marabella. In turn, Bligh and Antrim each became 5% working interest owners in our permit 38719. Unsuccessful exploratory wells were drilled on these two permits, and we charged $0.4 million against earnings in 1998 and $0.3 million in 1999. All of the acreage on the permit 38712 was surrendered in 2000. The exploratory well on permit 38716 has been temporarily abandoned pending a further evaluation. It is currently anticipated that this well will be re-entered and side-tracked to target a location to the west of the initial well. A five-year extension was granted on permit 38716 in 2001 upon the surrender of 50% of the acreage.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we will earn a 20% participating interest in petroleum exploration permit 38718 containing approximately 57,400 acres. In January 2001, the operator temporarily abandoned the Tuihu #1 exploratory well on permit 38718 pending further analysis. The permit now contains approximately 28,700 acres after a scheduled surrender during December 2000.

Costs Incurred. During 2001, our costs incurred in New Zealand totaled $54.5 million, including $25.7 million for drilling, $5.5 million for prospect costs, $22.5 million for production facilities, and $0.8 million in evaluation costs for the acquisition of the TAWN assets, which closed in January 2002. These costs also included $0.6 million of costs incurred on permits operated by others: $0.2 million of drilling costs and $0.4 million of prospect costs. As of December 31, 2001, our investment in New Zealand totaled approximately $84.4 million. As we have recorded proved undeveloped reserves relating to our successful drilling activities, $45.5 million of our investment costs has been included in the proved properties portion of oil and gas properties and $38.8 million has been included as unproved properties at the end of 2001. Our development strategy includes having Rimu/Kauri production on line for oil and gas sales in New Zealand near the end of the first quarter of 2002.

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. We retain a minimum 6% net profits interest from the sale of hydrocarbon products from the fields. The value of our net profits interest depends upon either the successful development of production from the fields by others or their sale of the fields.

Oil and Gas Reserves

The following table presents information regarding proved reserves of oil and gas attributable to our interests in producing properties as of December 31, 2001, 2000, and 1999. The information set forth in the table 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's audit was based upon review of production histories and other geological, economic, ownership, and engineering data provided by Swift.

In accordance with Securities and Exchange Commission guidelines, estimates of future net revenues from our proved reserves and the PV-10 Value must be made using oil and gas sales prices in effect as of the dates of such estimates and are held constant 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. Proved reserves as of December 31, 2001, were estimated based upon prices in effect at year-end. The weighted averages of such year-end prices domestically were $2.68 per Mcf of natural gas and $18.51 per barrel of oil, compared to $11.25 and $25.50 at year-end 2000 and $2.58 and $23.69 at year-end 1999. The weighted averages of such year-end 2001 prices for New Zealand were $1.18 per Mcf of natural gas and $18.25 per barrel of oil, compared to $0.71 and $22.30 in 2000. The weighted averages of such year-end 2001 prices for all our reserves, both domestically and in New Zealand, were $2.51 per Mcf of natural gas and $18.45 per barrel of oil, compared to $9.86 and $24.62 in 2000. 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 table. The proved reserves presented for all periods also exclude any reserves attributable to the volumetric production payment that was in effect in 2000 and 1999.

The table sets forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the Securities and Exchange Commission and their PV-10 Value. Operating costs, development 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.

At year-end 2001, 50% of the proved reserves were developed reserves. At year-end 2000, 45% of proved reserves were developed.

Changes in quantity estimates and the estimated present value of proved reserves are affected by the change in crude oil and natural gas prices at the end of each year. While our total proved reserves quantities, on an equivalent Bcfe basis, at year-end 2001 increased by 3% over reserves quantities a year earlier, the PV-10 Value of those reserves decreased 74% from the PV-10 Value at year-end 2000. This decrease in prices resulted in 47.1 Bcfe of downward reserve revision, solely attributed to the decrease in prices used in 2001. Our total proved reserves quantities at year-end 2000 increased by 38% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 310% from the PV-10 Value at year-end 1999. The PV-10 Value decrease in 2001 and the PV-10 increase in 2000 were heavily influenced by pricing decreases at year-end 2001 as compared to year-end 2000 and by pricing increases from year-end 2000 as compared to year-end 1999. Product prices for natural gas decreased 75% during 2001, from $9.86 per Mcf at December 31, 2000, to $2.51 per Mcf at year-end 2001, while oil prices decreased 25% between the two dates, from $24.62 to $18.45 per barrel. Product prices for natural gas increased 282% during 2000, from $2.58 per Mcf at December 31, 1999, to $9.86 per Mcf at year-end 2000,

	Year Ended December 31, 2001		
Estimated Proved Oil and Gas Reserves	Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	181,651,578	167,401,736	14,249,842
Proved undeveloped	143,260,547	121,087,764	22,172,783
Total	324,912,125	288,489,500	36,422,625
Net oil reserves (Bbl):			
Proved developed	23,759,574	20,393,142	3,366,432
Proved undeveloped	29,723,062	22,171,591	7,551,471
Total	53,482,636	42,564,733	10,917,903
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 344,478,834	$ 306,095,381	$ 38,383,453
Proved undeveloped	258,507,354	186,012,413	72,494,941
Total	$ 602,986,188	$ 492,107,794	$ 110,878,394

	Year Ended December 31, 2000		
Estimated Proved Oil and Gas Reserves	Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	215,169,833	215,169,833	—
Proved undeveloped	203,444,143	148,130,666	55,313,477
Total	418,613,976	363,300,499	55,313,477
Net oil reserves (Bbl):			
Proved developed	10,980,196	10,980,196	—
Proved undeveloped	24,153,400	12,962,513	11,190,887
Total	35,133,596	23,942,709	11,190,887
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 1,257,570,764	$ 1,257,570,764	$ —
Proved undeveloped	1,055,684,045	919,388,009	136,296,036
Total	$ 2,313,254,809	$ 2,176,958,773	$ 136,296,036

	Year Ended December 31, 1999		
Estimated Proved Oil and Gas Reserves	Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	174,046,096	174,046,096	—
Proved undeveloped	155,913,654	155,913,654	—
Total	329,959,750	329,959,750	—
Net oil reserves (Bbl):			
Proved developed	8,437,299	8,437,299	—
Proved undeveloped	12,368,964	12,368,964	—
Total	20,806,263	20,806,263	—
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 301,199,660	$ 301,199,660	$ —
Proved undeveloped	262,854,849	262,854,849	—
Total	$ 564,054,509	$ 564,054,509	$ —

while oil prices increased 4% between the two dates, from $23.69 to $24.62 per barrel. Product prices for natural gas increased 16% during 1999, from $2.23 per Mcf at December 31, 1998, to $2.58 per Mcf at year-end 1999, matched by a 111% increase in the price of oil between the two dates, from $11.23 to $23.69 per barrel.

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.

A portion of our proved reserves has been accumulated through our interests in the limited partnerships for which we serve as general partner. The estimates of future net cash flows and their present values, based on period end prices, assume that some of the limited partnerships in which we own interests will achieve payout status in the future. At December 31, 2001, 32 of the limited partnerships managed by us had achieved payout status.

No other reports on our reserves have been filed with any federal agency.

Oil and Gas Wells

As we continue to liquidate partnerships for those partnerships which voted to do so, our total well count decreased. Acquisitions such as Lake Washington, where we own nearly a 100% interest in all operated wells, have increased well ownership on a net basis. 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, 2001			
Gross	396	786	1,182
Net	297.0	467.9	764.9
December 31, 2000			
Gross	599	904	1,503
Net	165.2	484.7	649.9
December 31, 1999			
Gross	577	947	1,524
Net	105.5	449.2	554.7

[1]Excludes 48 service wells in 2001, 25 service wells in 2000, and 33 service wells in 1999. Also excludes 5 wells in 2001 and 3 wells in 2000 in New Zealand that were temporarily shut-in awaiting the commissioning of the Rimu Production Station.

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, 2001:

	Developed[1]		Undeveloped[1]	
	Gross	Net	Gross	Net
Alabama	10,091.69	2,861.81	775.72	291.86
Arkansas	762.00	557.57	2,040.15	679.48
Kansas	—	—	4,520.00	1,908.80
Louisiana	135,147.70	92,488.90	138,532.41	89,803.71
Mississippi	730.00	176.00	—	—
Texas	232,257.73	145,162.59	96,816.92	64,807.04
Wyoming	522.49	120.19	84,211.97	74,997.20
All other states	—	—	5,928.45	981.43
Offshore Louisiana	4,609.37	276.56	25,000.00	1,535.62
Offshore Texas	14,400.00	1,600.79	450.00	23.25
Total Domestic	398,520.98	243,244.41	358,275.62	235,028.39
New Zealand[2]	24,900.79	22,410.71	135,458.82	79,552.21
Total	423,421.77	265,655.12	493,734.44	314,580.60

[1]Fee mineral acres acquired in the Brookeland and Master Creek areas acquisition are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 114,655 undeveloped fee mineral acres for a total of 141,000 fee mineral acres.

[2]Excludes 24,602 gross and 23,805 net acres acquired in the TAWN acquisition that closed in January 2002, as well as 2,478 net acres acquired in the Antrim acquisition which closed in March 2002.

Partnerships

Prior to 1995, we funded a substantial portion of our operations through 109 limited partnerships which we formed and for which we have served as managing general partner. These partnerships raised a total of $509.5 million of capital, with the largest portion (81%) raised to acquire interests in producing properties. Eight of the earliest partnerships and 13 of the most recently formed partnerships were created to drill for oil and gas. In all of these partnerships Swift paid for varying percentages of the capital or front-end costs and continuing costs of the partnerships and, in return, received differing percentage ownership interests in the partnerships, along with reimbursement of costs and/or payment of certain fees. At year-end 2001, we continued to serve as managing general partner of 71 of these various partnerships, of which 65 are production purchase partnerships that have been in existence from six to fifteen years and the remainder are drilling partnerships that have been in existence from three to five years.

During 1997 and 1998, eight drilling partnerships formed between 1979 and 1985 and 21 of the production purchase partnerships sold their properties and were dissolved, in each case following a vote of the investors in the particular partnerships approving such liquidations. Between 1999 and 2001, the investors in all but six of the remaining partnerships voted to sell the properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. We anticipate that the liquidation and dissolution of the additional 65 partnerships should be substantially completed by the end of 2002. The remaining six partnerships will continue to operate until their limited partners vote otherwise.

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, oil spills, 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. Additionally, as managing general partner of limited partnerships, we are solely responsible for the day-to-day conduct of the limited partnerships' affairs and accordingly have liability for expenses and liabilities of the limited partnerships. We maintain comprehensive insurance coverage, including general liability insurance in an amount not less than $50.0 million, as well as general partner liability insurance. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage.

Employees

At December 31, 2001, we employed 209 persons. None of those employees were represented by a union. Relations with employees are considered to be good.

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.

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.

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.

Petajoules — A unit of energy equivalent to .95 Bcf of 1,000 Btu of natural gas.

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. Proved undeveloped oil and gas reserves are 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.

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.

Volumetric Production Payment — The 1992 agreement pursuant to which we financed the purchase of certain oil and natural gas interests and committed to deliver certain monthly quantities of natural gas.

Those portions of the Form 10-K Report for the year ended December 31, 2001, not included in this Annual Report to Shareholders (including certain portions of Item 1–Business pertaining to "Competition" and "Regulations," Item 3–Legal Proceedings, Item 4–Submission of Matters to a Vote of Security Holders, Item 9–Changes in and Disagreements with Accountants on Accounting and Financial Disclosure, and Item 14–Exhibits, Financial Statement Schedules, and Reports on Form 8-K), with no disclosures having been made as to Items 4 and 9, will be provided without charge to shareholders making a written request to Scott Espenshade, Director of Investor Relations, Swift Energy Company, 16825 Northchase Drive, Suite 400, Houston, Texas 77060-6098. 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, Swift Energy Company
Chairman, Swift Energy International

Terry E. Swift
President & CEO, Swift Energy Company
President, Swift Energy International

G. Robert Evans
Retired Chairman & CEO
Material Sciences Corporation

Henry C. Montgomery
Chairman & Founder
Montgomery Financial
Services Corp.

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

Harold J. Withrow
Consultant

Raymond O. Loen
Director Emeritus

OFFICERS

Terry E. Swift
President & Chief Executive Officer

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

Bruce H. Vincent
Executive Vice President–Corporate
Development, Secretary

Alton D. Heckaman, Jr.
Senior Vice President–Finance,
Chief Financial Officer

James M. Kitterman
Senior Vice President–Operations

Victor R. Moran
Senior Vice President–Energy
Marketing & Business Development

Gerald B. Long
Vice President–Production Operations

James P. Mitchell
Vice President–Land & Property
Transactions

Khushroo N. J. Patel
Vice President–Geophysics

Thomas E. Schmidt
Vice President–Exploration &
Development

Tara L. Seaman
Vice President–Acquisitions,
Dispositions & Reserves

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

D. Wynn Ibach
General Counsel

CORPORATE HEADQUARTERS

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16825 Northchase Drive, Suite 400
Houston, Texas 77060-6098
Telephones: (281) 874-2700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANIES

Swift Energy International, Inc.
Houston, Texas

SWENCO-Western, Inc.
Houston, Texas

Swift Energy Marketing Company
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

Arthur Andersen LLP
711 Louisiana, Suite 1300
Houston, Texas 77002

COUNSEL

Jenkens & Gilchrist
1100 Louisiana, Suite 1800
Houston, Texas 77002

COMMON STOCK, 2000 AND 2001

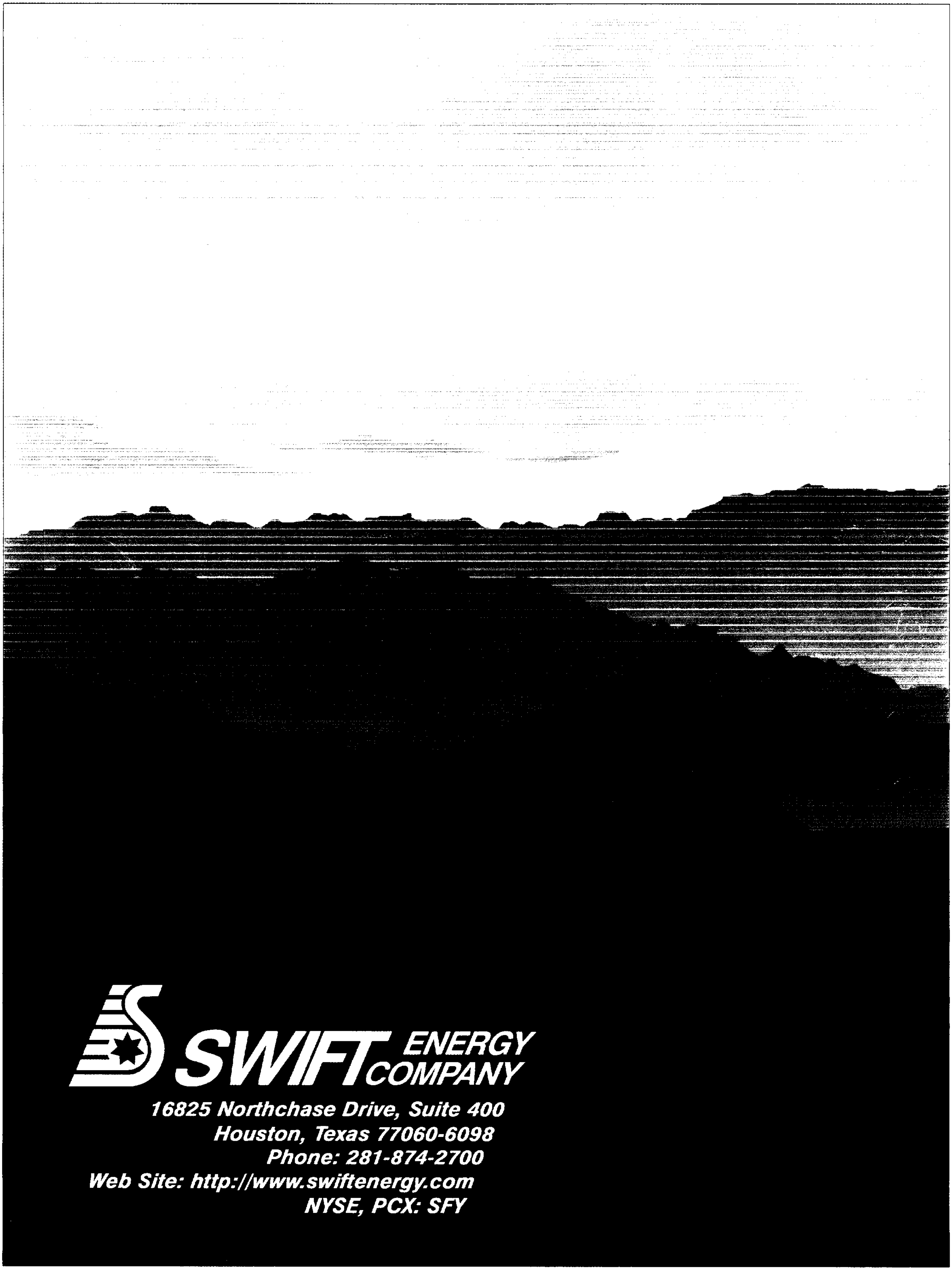
Our common stock is traded on the New York Stock Exchange and the Pacific Exchange, Inc., under the symbol "SFY." The high and low quarterly sales prices for the common stock for 2000 and 2001 were as follows:

	2000				2001			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$9.75	$15.00	$20.38	$28.81	$28.91	$27.70	$19.00	$16.66
High	$17.88	$29.56	$41.88	$43.50	$37.50	$37.70	$32.55	$25.14

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 383 stockholders of record as of December 31, 2001.

Annual Meeting
4 p.m., Tuesday, May 14, 2002
Marriott Hotel
255 N. Sam Houston Parkway East
Houston, Texas 77060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NYSE, PCX: SFY