SWIFT ENERGY CO
Form 10-K/A
May 06, 2004

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K/A
Amendment No. 2

Annual Report Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2002

Commission File Number 1-8754

SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas	74-2073055
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Dr., Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class:	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange
	Pacific Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes X No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes X No

The aggregate market value of the voting stock held by non-affiliates at March 1, 2003 was approximately $246,766,019.

The number of shares of common stock outstanding as of December 31, 2002 was 27,201,509 shares of common stock, $.01 par value.

Documents Incorporated by Reference

Document	Incorporated as to
Notice and Proxy Statement for the Annual Meeting of Shareholders to be	Part III, Items 10, 11, 12, and 13

held May 13, 2003

EXPLANATORY NOTE

This Amendment No. 2 to the Swift Energy Company Annual Report on Form 10-K for the fiscal year ended December 31, 2002 is being filed solely to correct typographical errors in the Certifications for the Chief Executive Officer and Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Form 10-K
Swift Energy Company and Subsidiaries

(1) Incorporated by reference from Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 13, 2003.

PART I

Items 1 and 2. Business and Properties

See pages 18 and 19 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 and inland waters 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, 2002, we had interests in 932 wells located domestically in three states, in federal offshore waters, and in New Zealand. We operated 820 of these wells representing 95% our proved reserves. At year-end 2002, we had estimated proved reserves of 749.4 Bcfe, of which approximately 44% was natural gas, 42% crude oil, and 14% NGLs, and overall 60% was proved developed. Our proved reserves are concentrated 41% in Texas, 35% in Louisiana, and 21% in New Zealand.

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

Area	Location	% of Year-End 2002 Proved Reserves
AWP Olmos	South Texas	30%
Brookeland	East Texas	6%
Lake Washington	South Louisiana	25%
Masters Creek	Central Louisiana	10%
Rimu/Kauri	New Zealand	12%
TAWN	New Zealand	9%

% of Total	92%

We have a well-balanced portfolio of oil and gas properties and prospects. 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 Masters Creek and Brookeland 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 2002 year-end proved reserves and 2002 production, we calculated our average reserve life as 17.4 years domestically and 10.0 years in New Zealand.

We have increased our proved reserves from 361.5 Bcfe at year-end 1997 to 749.4 Bcfe at year-end 2002, which has resulted in the replacement of 278% of our production during the same five-year period. Our five-year average reserves replacement costs were $1.25 per Mcfe. Our average annual reserve replacement costs for the last five years, starting with 2002 were $0.96, $3.30, $0.81, $1.27 and $1.20 per Mcfe. In 2002, we increased our proved reserves by 16%, which replaced 308% of our 2002 production. Our 2002 production increased by 11% in relation to 2001 production. We have increased our production from 25.4 Bcfe at year-end 1997 to 49.8 Bcfe at year-end 2002. Primarily due to increased production, this has resulted in average annual growth in net cash provided by operating activities of 5% per year from year-end 1997 to year-end 2002, even though in 2002 net cash provided by operating activities fell 49% due to pricing changes.

Through intensive efforts, we have developed an inventory of exploration and development prospects, identifying drilling locations through integrated geological and geophysical studies of our undeveloped acreage and other prospects. As a result, we added 184.7 Bcfe of proved reserves through drilling in 2000 (122.5 Bcfe from New Zealand), 105.8 Bcfe in 2001 (17.4 Bcfe from New Zealand), and 83.9 Bcfe in 2002 (15.9 Bcfe from New Zealand). The 2002 additions were primarily a result of our development success rate, as 17 of 23 domestic development wells drilled were successful, while three of seven domestic exploratory wells were successful.

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. 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. In the first quarter of 2002, we purchased interests in the four TAWN fields in New Zealand for approximately $51.4 million, which also included significant infrastructure, after purchase price adjustments.

We currently plan to spend $115 to $130 million in total capital expenditures in 2003, excluding acquisition costs and net of approximately $5 million to $15 million in non-core property dispositions. The budget for 2003 is largely dependent upon our performance and commodity pricing during the year. Domestic activities account for 85% of our budgeted spending, primarily in the Lake Washington Area.

Competitive Strengths and Business Strategy

We believe that our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to accomplish our goals.

Balanced Approach to Adding Reserves

When we believe the market favors increasing reserves through acquisitions, we apply our considerable experience in evaluating and negotiating prospective acquisitions. For example, in 1998, when commodity prices were relatively weak, 32% of our capital expenditures consisted of property acquisitions, with 37% committed to our drilling activities. In contrast, in 2001, when commodity prices were relatively strong in the first half of the year, only 15% of our capital expenditures were spent on property acquisitions, with our drilling expenditures increasing to 67% of total capital expended. We believe this balanced approach has resulted in our ability to grow reserves in a relatively low cost manner, while participating in the upside potential of exploration.

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. Generally, we seek to acquire properties with the potential for additional reserves and production through development and exploration efforts. In addition, we seek to enhance the results of our drilling and production efforts through the implementation of advanced technologies.

During 2002, in response to strong oil prices throughout the year, we focused our capital expenditures on the Lake Washington Area domestically and on the TAWN acquisition in New Zealand. Although oil prices remained strong in 2002, natural gas prices for most of the year were lower than prior year levels, and our cash flow generated due to these commodity prices decreased, as expected, even though production increased. As a result of lower cash flow in 2002, we reduced our capital expenditures to $155.2 million. Of this amount, $58.4 million was spent on acquisitions, mainly the TAWN acquisition in New Zealand. We spent $42.7 million on drilling in the United States, with $34.4 for development drilling and $8.3 million for exploratory drilling. In New Zealand we spent $22.9 million on drilling, with $12.6 million for development drilling and $10.3 million for exploratory drilling. We also spent $10.6 million constructing a gas processing plant in New Zealand. The remaining capital expenditures of $20.6 million were spent primarily on leasehold, seismic, and geological costs of prospects, both in the United States and New Zealand. During 2002, we principally relied upon cash flows from operations of $71.6 million, net proceeds from the issuance of long-term debt of $195.0 million, and net proceeds from our public stock offering of $30.5 million, less the repayment of bank borrowings of $134.0 million, to fund our capital expenditures.

In 145 transactions from 1979 to 2002, we have acquired approximately $695.7 million of producing oil and gas properties on behalf of our co-investors and ourselves. We acquired, for our own account, approximately $339.2 million of producing properties, with original proved reserves estimated at 468.5 Bcfe during this period. Our producing property acquisition expenditures in the past three years were $64.2 million in 2002, $41.3 million in 2001, and $34.2 million in 2000. Our acquisition costs have averaged $0.83 per Mcfe over this three-year period. Our acquisition cost in 2002 averaged $0.87 per Mcfe.

Concentrated Focus on Core Areas

Our concentration of reserves and our significant acreage positions in our core areas allow us to realize economies of scale in drilling and production. We enhance the value of this concentration by acting as the operator of 95% of our proved reserves at year-end 2002. Our operational control allows us to better manage production, control our expenses, allocate capital and time field development. We intend to continue to acquire large acreage positions in under-explored and under-exploited areas, where, as operator, we can exploit successful discoveries to create new core areas or grow production from developed fields. In executing this strategy:

- We focus our resources on acquiring properties that we can operate, and in which we can obtain a significant working interest. With operational control, we can apply our technical and operational expertise to optimize our exploration and exploitation of the properties that we acquire.

- We acquire and operate domestic properties in a limited number of geographic areas. Operating in a concentrated area helps us to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees, minimizing incremental costs of increased drilling and production.

- We continue to believe in natural gas prospects and reserves in the United States. The natural gas market in the United States has a well-developed infrastructure. Natural gas is viewed by many as the preferred fuel in North America for several reasons, including environmental concerns. We have a strong inventory of natural gas that can be developed in a higher priced environment.

- We seek to operate large acreage positions with high exploration and development potential. For example, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest. The Masters Creek, Brookeland and Lake Washington areas also had significant additional development potential when we first acquired our interest in those areas.

Ability to Build Upon our Recent Discoveries and Acquisitions in New Zealand

Our New Zealand activities provide us with long-term growth opportunities and significant potential reserves in a country with stable political and economic conditions, existing oil and gas infrastructure, and favorable tax and royalty regimes. We have completed construction of our Rimu production and gas processing facilities, which became operational in May 2002 and enabled us to begin the sale of production from the Rimu/Kauri area. We were able to bring our Rimu discovery on commercial production in a significantly shorter period than any other similar project previously undertaken in New Zealand of which we are aware.

In January 2002, we acquired the TAWN fields. In our TAWN acquisition, we also acquired extensive associated processing facilities and pipelines, which give us a competitive advantage through infrastructure that complements our existing fields, providing us with increased access to export terminals and markets and additional excess processing capacity for both oil and natural gas.

Experienced Technical Team

We employ oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 25 years of experience in their technical fields and have been employed by Swift for an average of over 10 years. We continually apply our extensive in-house expertise and current advanced technologies to benefit our drilling and production operations. We have developed a particular expertise in drilling horizontal wells at vertical depths below 10,000 feet, often in a high-pressure environment, involving single or dual lateral legs of several thousand feet. This results in an integrated approach to exploration using multidisciplinary data analysis and interpretation that has helped us identify a number of exploration prospects.

We use various recovery techniques, including water flooding and acid treatments, fracturing reservoir rock through the injection of high-pressure fluid, gravel packing, and inserting coiled tubing velocity strings to enhance and maintain gas flow. We believe that the application of fracturing technology and coiled tubing has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos Area.

We have increasingly used 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. As a result, we have maintained internal seismic expertise and have compiled an extensive database.

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

Financial Discipline

We practice a disciplined approach to financial management and have historically maintained a strong capital structure that preserves our ability to execute our business plan. Key components of our financial discipline include maintaining a capital budget balanced between drilling and acquisitions, establishing leverage targets that are reasonable given the volatility of the oil and gas markets, and opportunistically accessing the capital markets. As of December 31, 2002, our long-term debt comprised approximately 47% of our total capitalization. We applied the net proceeds from our common stock offering and debt offering in April 2002 in the amount of $225.5 million to reduce amounts outstanding under our credit facility. At December 31, 2002, we had $194.2 million of available borrowing capacity. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development, and exploitation activity with the net proceeds from our common stock offering and debt offering, we implemented our strategy of matching long-lived assets with long-term financing.

Domestic Core Operating Areas

AWP Olmos Area. As of December 31, 2002, we owned approximately 27,900 net acres in the AWP Olmos Area in South Texas. 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 66% gas. At year-end 2002, we owned interests in 495 wells and operated 494 wells in this area producing gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all our operated wells.

In 2002, we performed four fracture extensions and installed coiled tubing velocity strings in five wells. At year-end 2002, we had 128 proved undeveloped locations. Also in 2002, we purchased interests in the AWP Olmos area from partnerships we managed. Our planned 2003 capital expenditures in this area will focus on drilling 10 wells and performing fracture extensions and installing coiled tubing velocity strings to maintain a flat production profile.

Brookeland Area. As of December 31, 2002, we owned drilling and production rights in 76,259 net acres and 3,500 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 55% oil and natural gas liquids. At year-end 2002, we had 13 proved undeveloped locations in this area. Our planned 2003 capital expenditures in this area include drilling one development well.

Lake Washington Field. As of December 31, 2002, we owned drilling and production rights in 11,080 net acres in the Lake Washington Field. This area is located in Plaquemines Parish in South Louisiana. The reserves are approximately 98% 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 1,700 feet to greater than 9,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its inception in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 38 producing wells is gathered from three platforms located in water depths from 6 to 11 feet, with drilling and workover operations performed with barge rigs. In 2002, 23 development wells and four exploratory wells were drilled in the area; 17 development and two exploratory wells were successful. At year-end 2002, we had 63 proved undeveloped locations in this field. Our planned 2003 capital expenditures in this area include drilling 50 to 60 development wells and one saltwater disposal well.

Masters Creek Area. As of December 31, 2002, we owned drilling and production rights in 77,475 net acres and 107,000 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 72% oil and natural gas liquids. At year-end 2002, we had 12 proved undeveloped locations in the area. Our planned 2003 capital expenditures in this area include drilling one development well.

Domestic Emerging Growth Areas

The Frio Trend. We have 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, we had two discoveries in the area in 2001, one in the Rome prospect in Willacy County and the other in the Siena prospect in Kenedy County. In 2002, we participated in a successful non-operated well with a 33% working interest in the Milan prospect in Kenedy county. We plan to participate in drilling two development wells in 2003 in this area.

The Wilcox Sands. We 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. Our working interests in the two wells are 73% and 60%, respectively. The third well, in which we have a 25% working interest, was in the Falcon Ridge prospect in Zapata County, Texas. We plan to participate in one development well in this area in 2003.

The Woodbine Formation. The Woodbine formation is located in southeast Texas in San Jacinto, Polk, and Tyler counties. We drilled one well to the Woodbine formation in 2001, in the Lion prospect in San Jacinto County, Texas, to a depth of 15,000 feet. Although hydrocarbon-bearing intervals were found, the well was deemed noncommercial. The Company has two other Woodbine prospects, the Jaguar and Bobcat prospects, both located in Polk County.

The Miocene Sands. We successfully drilled our first exploratory well in the Miocene sands in our 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. Through 2002, we have drilled 28 wells in this area.

New Zealand Core Operating Areas

Our activity in New Zealand began in 1995. As of December 31, 2002, our permit 38719, which we operate, included approximately 49,800 acres in the Taranaki Basin of New Zealand's north island. This acreage includes our Rimu and Kauri areas as well as our Tawa and Matai prospects.

We expanded our operation in New Zealand in January 2002 with our TAWN purchase of Southern Petroleum (NZ) Exploration, Limited, from Shell New Zealand, through which we acquired interests in four fields and significant infrastructure assets.

In March 2002, we completed the acquisition of all of the New Zealand assets of Antrim. These assets included a 5% working interest in the Swift-operated permit 38719, increasing the Company's interest in this permit to 95%. An additional 7.5% interest was also acquired in permit 38716 (Huinga prospect), increasing the Company's interest to 15%.

In August 2002, we were awarded two additional onshore permits, permits 38756 and 38759. These permits include approximately 8,100 and 20,400 gross acres, respectively, in proximity to our permit 38719.

In September 2002, we completed the acquisition of Bligh's 5% working interest in permit 38719 and 5% interest in the Rimu petroleum mining permit 38151, along with their 3.24% working interest in the four TAWN petroleum mining licenses. The Company's interests in permit 38719, petroleum mining permit 38151, and the TAWN petroleum mining licenses are now 100%.

In December 2002, we agreed to acquire an additional 50% interest in permit 38718 (Tuihu prospect) from Shell New Zealand through an existing pre-emptive right under the joint operating agreement. Following the transaction, SENZ will sell a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale, which are subject to certain government notifications, approvals and consents, will result in SENZ holding a 50% working interest in this permit. We were named operator of the permit. Permit 38718 contains the Tuihu #1 exploratory well, which was drilled in 2001 and temporarily abandoned. Our 2003 budget calls for a re-entry of this well, which will sidetrack or deepen the original well.

As of December 31, 2002, our gross investment in New Zealand totaled approximately $172.8 million. Approximately $145.0 million of our investment costs have been included in the proved properties portion of our oil and gas properties, while $27.8 million is included as unproved properties.

Rimu Area. Early in 2002, we were awarded petroleum mining permit 38151 by the New Zealand Ministry for Economic Development for the development of the

Rimu discovery over an approximately 5,500 acre area for a primary term of 30 years. Commercial production from the Rimu area began in May 2002.

During the first quarter of 2002, the Rimu-A2 sidetrack was completed and recently underwent fracture stimulation, which was unsuccessful. We plan a CO2 stimulation project during the first half of 2003 to improve its productibility. The Rimu-B3 development well was also sidetracked in early 2002 but was unsuccessful.

Kauri Area. During 2002, three wells were drilled in the Kauri area. The Kauri-A1 exploratory well was drilled to the Upper Tariki sand, the Kauri-A3 development well was drilled to the shallow Manutahi sands, and the Kauri-A4 exploratory well was drilled through the Kauri sands and on down to the Lower Tariki sand, which was found to be too wet for commercial production. After the drilling of the Kauri-A4 well was completed in October 2002, pipe was set in the well and perforated over approximately 33 feet of the Kauri sands in preparation for a hydraulic fracture stimulation in early 2003.

TAWN Area. The TAWN acquisition in January 2002 consisted of a 96.76% working interest in four petroleum mining licenses, or PML, covering producing oil and gas fields, and extensive associated hydrocarbon-processing facilities and pipelines, which give us a competitive advantage through infrastructure that complements our existing fields, providing us with increased access to export terminals and markets and additional excess processing capacity for both oil and natural gas. The TAWN assets are located approximately 17 miles north of the Rimu area.

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 four fields include 17 wells where the purchaser of gas, Contact Energy, has contracted to take minimum quantities and can call for higher production levels to meet electrical demand in New Zealand. Sales gas deliveries to Contact have exceeded the contract minimum during all of 2002.

Solution gas gathered from the Waihapa Production Station ("WPS") flows to the Tariki Ahuroa gas plant ("TAG"). The current processing capacity of the WPS facility is up to 15,000 barrels of oil and 40 MMcf of natural gas per day. Processing capacity tests conducted following facility modifications completed in the third quarter have confirmed a 12% increase in the gas processing capacity of the TAG plant. 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. An additional 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.

We have a service agreement with the owner of the Omata Tank Farm to utilize the blending, storage, and export capabilities of the facility. The operator of the facility provides services for a fixed fee per barrel received and other variable costs as required by the agreement. Under the terms of the agreement, crude oil produced from the TAWN and Rimu/Kauri areas have access to the Omata Tank Farm.

Our current contract with Shell Petroleum Mining (SPM), which purchases all of our New Zealand crude oil production, runs through the end of 2003. The delivery point for our crude oil sales is the ship's flange. SPM and the Omata

Tank Farm coordinate logistical issues for shipments, and thus SPM's decisions regarding sales from the Omata Tank Farm can affect the timing of sales of that portion of our production.

Rimu Production Station. We completed construction on the Rimu Production Station ("RPS") during the first quarter of 2002, and production was processed through this facility beginning in the second quarter of 2002. Our oil production processed through the RPS is transported the 17 miles by truck to our WPS facility and then sent by pipeline to the Omata Tank Farm. Our natural gas production processed through the RPS is sold to Genesis Power Ltd. under a long-term contract. Natural gas prices are substantially lower in New Zealand, as compared to domestic prices, largely due to the fact that the natural gas market has been dominated by one large field, the Maui Field, which supplies approximately 70% of the natural gas supply but is due to be depleted by 2007.

New Zealand Emerging Growth Areas

The Tawa prospect is located northwest of the Rimu and Kauri areas in the same permit. Its main targets are the Kapuni sands, the Kauri sandstones, 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 and Urenui sandstones. It was identified based upon the analysis of the two-dimensional seismic data Swift acquired in 2000.

The Tuihu prospect, permit 38718, is located northeast of our TAWN Area. In December 2002, we agreed to acquire an additional 50% interest in permit 38718 from Shell New Zealand though an existing pre-emptive right under the joint operating agreement. Following the transaction, SENZ will sell a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale, which are subject to certain government notifications, approvals and consents, will result in SENZ holding a 50% working interest in this permit. We were named operator of the permit. Permit 38718 contains the Tuihu #1 exploratory well, which was drilled in 2001 and was temporarily abandoned. Our 2003 budget calls for a re-entry of this well, which will sidetrack or deepen the original well.

The Huinga prospect, permit 38716, is located northeast of our Rimu/Kauri areas. An exploratory well was drilled on this permit, of which we own 15%, in 1998 and was temporarily abandoned. This well was re-entered in 2002 and was unsuccessful. The operator is currently re-evaluating this prospect.

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, 2002, 2001, and 2000. 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, 2002, were estimated based upon prices in effect at year-end. The weighted averages of such year-end prices domestically were $4.23 per Mcf of natural gas, $29.36 per barrel of oil, and $17.30 per barrel of NGL, compared to $2.68, $18.51, and $11.00 at year-end 2001 and $11.25, $25.50, and $20.30 at year-end 2000, respectively. The weighted averages of such year-end 2002 prices for New Zealand were $1.48 per Mcf of natural gas, $28.80 per barrel of oil, and $12.24 per barrel of NGL, compared to $1.18, $18.25, and $8.90 in 2001, respectively. The weighted averages of such year-end 2002 prices for all our reserves, both domestically and in New Zealand, were $3.49 per Mcf of natural gas, $29.27 per barrel of oil, and $16.54 per barrel of NGL, compared to $2.51, $18.45, and $10.70 in 2001, respectively. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following table.

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.

	Year Ended December 31,	
	Total	Domestic
Estimated Proved Oil and Gas Reserves		
Net natural gas reserves (Mcf):		
Proved developed	233,514,572	149,731,562
Proved undeveloped	93,217,100	90,092,500
Total	326,731,672	239,824,062
Net oil and NGL reserves (Bbl):		
Proved developed	35,928,395	26,530,112
Proved undeveloped	34,510,568	32,499,528
Total	70,438,963	59,029,640
Estimated Present Value of Proved Reserves		
Estimated present value of future net cash flows from proved reserves discounted at 10% annum:		
Proved developed	$ 679,356,172	$ 516,832,848
Proved undeveloped	481,833,151	456,632,145

	Total	Domestic
Total	$ 1,161,189,323	$ 973,464,993

	Year Ended December 31,	
	Total	Domestic
Estimated Proved Oil and Gas Reserves		
Net natural gas reserves (Mcf):		
Proved developed	181,651,578	167,401,736
Proved undeveloped	143,260,547	121,087,764
Total	324,912,125	288,489,500
Net oil and NGL reserves (Bbl):		
Proved developed	23,759,574	20,393,142
Proved undeveloped	29,723,062	22,171,591
Total	53,482,636	42,564,733
Estimated Present Value of Proved Reserves		
Estimated present value of future net cash flows from proved reserves discounted at 10% annum:		
Proved developed	$ 344,478,834	$ 306,095,381
Proved undeveloped	258,507,354	186,012,413
Total	$ 602,986,188	$ 492,107,794

	Year Ended December 31,	
	Total	Domestic
Estimated Proved Oil and Gas Reserves		
Net natural gas reserves (Mcf):		
Proved developed	215,169,833	215,169,83
Proved undeveloped	203,444,143	148,130,66
Total	418,613,976	363,300,49
Net oil and NGL reserves (Bbl):		
Proved developed	10,980,196	10,980,19
Proved undeveloped	24,153,400	12,962,51
Total	35,133,596	23,942,70

Estimated Present Value of Proved Reserves
Estimated present value of future net cash flows
from proved reserves discounted at 10% annum:

Proved developed	$ 1,257,570,764	$ 1,257,570,76
Proved undeveloped	1,055,684,045	919,388,00
Total	$ 2,313,254,809	$ 2,176,958,77

At year-end 2002, 60% of the proved reserves were developed reserves. At year-end 2001, 50% of proved reserves were developed. 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. Our total proved reserves quantities at year-end 2002 increased by 16% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 93% from the PV-10 Value at year-end 2001. While our total proved reserves quantities, on an equivalent Bcfe basis, at year-end 2001 increased by 3% over reserves quantities in 2000, the PV-10 Value of those reserves decreased 74% from the PV-10 Value at year-end 2000. This decrease in 2001 prices resulted in 47.1 Bcfe of downward reserves revision, solely attributed to the decrease in prices used in 2001. The PV-10 Value increase in 2002 and the PV-10 decrease in 2001 were heavily influenced by pricing increases at year-end 2002 as compared to year-end 2001 and by pricing decreases from year-end 2001 as compared to year-end 2000. Product prices for natural gas increased 39% during 2002, from $2.51 per Mcf at year-end 2001 to $3.49 at year-end 2002, while oil prices increased 59% between the two dates, from $18.45 to $29.27 per barrel. 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, matched by a 4% increase in the price of oil between the two dates, from $23.69 to $24.62 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.

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

Oil and Gas Wells

As we continued to liquidate partnerships for those partnerships which voted to do so, our total gross 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, 2002:			
Gross	342	555	897
Net	278.9	479.8	758.7
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

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, 2002:

	Developed (1)		Undeveloped (1)	
	Gross	Net	Gross	Net
Alabama	9,686.01	2,859.10	775.72	291.87
Arkansas	602.00	486.38	280.15	280.15
Louisiana	91,543.91	71,989.49	26,525.22	17,858.76
Mississippi	630.03	163.32	60.00	15.80
Texas	183,416.49	122,312.29	72,737.12	46,983.18
Wyoming	120.00	21.06	73,777.00	70,745.32
All other states	320.00	266.66	160.00	17.32
Offshore Louisiana	4,609.37	276.56	5,000.00	258.34
Offshore Texas	14,400.00	1,600.79	---	---
Total Domestic	305,327.81	199,975.65	179,315.21	136,450.74
New Zealand	6,760.00	6,454.00	163,262.37	112,652.01
Total	312,087.81	206,429.65	342,577.58	249,102.75

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2002:

		Gross Wells				Net We		
Year	Type of Well	Total	Producing	Dry	Temporarily Abandoned	Total	Producing	D
2000	Exploratory-Domestic	9	5	4	--	6.2	3.4	2
	Development-Domestic	59	52	7	--	42.4	37.1	5
	Exploratory-New Zealand	2	2	--	--	1.8	1.8	
2001	Exploratory-Domestic	11	6	5	--	6.2	4.0	2
	Development-Domestic	36	36	--	--	29.5	29.5	
	Exploratory-New Zealand	2	--	1	1	1.1	--	0
	Development-New Zealand	4	2	2	--	3.6	1.8	1
2002	Exploratory-Domestic	7	3	4	--	5.0	2.3	2
	Development-Domestic	23	17	6	--	23.0	17.0	6
	Exploratory-New Zealand	3	2	1	--	2.2	2.0	0
	Development-New Zealand	3	2	1	--	3.0	2.0	1

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 2002 totaled $5.0 million and ranged from $450 to $2,174 per well per month.

Marketing of Production

Domestically, 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. Eastex Crude Company and Contact Energy in New Zealand each accounted for 10% or more of our total revenues during the year ended December 31, 2002, with those purchasers accounting for approximately 28% of revenues in the aggregate. For the year ended December 31, 2001, Eastex Crude Company and subsidiaries of Enron accounted for approximately 29% 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 (APPI) Tapis posting, less the cost of storage, trucking, and transportation.

Our gas production from our TAWN fields is sold under a long-term contract with Contact Energy. Our gas production from the Rimu field is sold to Genesis Power Ltd. under a long-term contract. Additional production volumes from our TAWN fields, over the contract minimum, can be sold to Contact Energy or Genesis Power Ltd. at prevailing market rates.

Our New Zealand natural gas liquids production is sold to RockGas under long-term contracts tied to New Zealand's domestic natural gas liquids market.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and gas production for the three-year period ended December 31, 2002. "Net" production is production that is owned by us 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,		
	2002	2001	200
Net Sales Volume:			
Oil (Bbls) (1)	3,770,128	3,055,373	2
Gas (Mcf)(2) (3)	27,131,578	26,458,958	27
Gas equivalents (Mcfe)	49,752,346	44,791,202	42
Average Sales Price:			
Oil (Per Bbl) (1)	$ 20.88	$ 22.64	$
Gas (Per Mcf) (3)	$ 2.30	$ 4.23	$
Average Production Cost (per Mcfe)	$ 0.83	$ 0.82	$

In the table above, for 2002, natural gas liquids have been combined with oil and condensate for reporting purposes. The natural gas liquids production for 2002 was 1,173,504 barrels, at an average price of $12.82 per barrel.

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.

Competition

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and gas properties, as well as for equipment, labor and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition.

Regulations

Environmental Regulations

Our exploration, production and marketing operations are regulated extensively at the international, federal and state and local levels. These regulations affect the costs, manner and feasibility of our operations. As an owner of oil and gas properties, we are subject to international, federal, state and local regulation of discharge of materials into, and protection of, the environment. We have made and will continue to make significant expenditures in our efforts to comply with the requirements of these environmental regulations, which may impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could increase our compliance costs and might hurt our business.

We are subject to state and local regulations domestically and are subject to New Zealand regulations that impose permitting, reclamation, land use, conservation and other restrictions on our ability to drill and produce. These laws and regulations can require well and facility sites to be closed and reclaimed. We frequently buy and sell interests in properties that have been operated in the past, and as a result of these transactions we may retain or assume clean-up or reclamation obligations for our own operations or those of third parties.

United States Federal, State and New Zealand Regulation of Oil and Natural Gas

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the federal government and are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. Some recent FERC proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines.

Our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation. However, the ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation.

Production of any oil and gas by us will be affected to some degree by state regulations. Many states in which we operate have statutory provisions regulating the production and sale of oil and gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and gas and to protect correlative rights to produce oil and gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and gas produced by assigning allowable rates of production to each well or proration unit. Likewise, the government of New Zealand regulates the exploration, production, sales and transportation of oil and natural gas.

Federal Leases

Some of our properties are located on federal oil and gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and orders affect the terms of leases, exploration and development plans, methods of operation, and related matters.

Employees

At December 31, 2002, we employed 234 persons. Of these employees, 57 are in New Zealand, eight of whom are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good.

Facilities

We occupy approximately 93,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten-year lease expiring in 2005. The lease requires payments of approximately $167,000 per month. In New Zealand we lease approximately 15,000 square feet of office space, under leases expiring in 2009. The lease requires payments of approximately $16,000 per month. We also have field offices in various locations from which our employees supervise local oil and gas operations.

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. These partnerships began liquidating and selling their properties in 1996. At year-end 2002, we continued to serve as managing general partner for six remaining partnerships, all of which are drilling partnerships that have been in existence from four to six years.

Available Information

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

Glossary of Abbreviations and Terms

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

Bbl -- Barrel or barrels of oil.

Bcf -- Billion cubic feet of natural gas.

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

BOE -- Barrels of oil equivalent.

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

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

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

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.

Terajoule -- A unit of energy equivalent to 1,000 gigajoules.

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.

Item 3. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation incidental to our business.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted during the fourth quarter of 2002 to a vote of security holders.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

COMMON STOCK, 2001 AND 2002

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 2001 and 2002 were as follows:

	2001				2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$28.91	$27.70	$19.00	$16.66	$15.55	$13.44	$10.40	$6.80
High	$37.50	$37.70	$32.55	$25.14	$20.58	$20.53	$15.23	$10.54

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 366 stockholders of record as of December 31, 2002.

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Item 6. Selected Financial Data

	2002	2001	2000	
Revenues				
Oil and Gas Sales	$141,195,713	$181,184,635	$189,138,947	$
Fees and Earned Interests(2)	$67,173	$427,583	$331,497	
Interest Income	$263,738	$49,281	$1,339,386	
Other, Net	$8,443,187	$2,145,991	$815,116	

Total Revenues	$149,969,811	$183,807,490	$191,624,946	$
Operating Income (Loss)	$18,408,289	($34,192,333)	$93,079,346	
Net Income (Loss)	$11,923,227	($22,347,765)	$59,184,008	
Net Cash Provided by Operating Activities	$71,626,314	$139,884,255	$128,197,227	
Per Share Data				
Weighted Average Shares Outstanding(3)	26,382,906	24,732,099	21,244,684	
Earnings (Loss) per Share--Basic(3)	$0.45	($0.90)	$2.79	
Earnings (Loss) per Share--Diluted(3)	$0.45	($0.90)	$2.51	
Shares Outstanding at Year-End	27,201,509	24,795,564	24,608,344	
Book Value per Share	$13.42	$12.61	$13.50	
Market Price(3)				
High	$20.58	$37.70	$43.50	
Low	$6.80	$16.66	$9.75	
Year-End Close	$9.67	$20.20	$37.63	
Pro forma amounts assuming 1994 change in Accounting principle is applied retroactively(2)				
Net Income (Loss)	---	---	---	
Earnings (Loss) per Share--Basic (3)	---	---	---	
Earnings (Loss) per Share--Diluted (3)	---	---	---	
Assets				
Current Assets	$29,768,199	$36,752,980	$41,872,879	
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization	$721,617,941	$628,304,060	$524,052,828	$
Total Assets	$767,005,859	$671,684,833	$572,387,001	$
Liabilities				
Current Liabilities	$46,884,184	$73,245,335	$64,324,771	
Long-Term Debt	$324,271,973	$258,197,128	$134,729,485	$
Total Liabilities	$401,932,675	$359,032,113	$240,232,846	$
Stockholders' Equity	$365,073,184	$312,652,720	$332,154,155	$
Number of Employees	234	209	181	
Producing Wells				
Swift Operated	820	854	817	
Outside Operated	112	381	711	
Total Producing Wells	932	1,235	1,528	
Wells Drilled (Gross)	36	53	70	
Proved Reserves				
Natural Gas (Mcf)	326,731,672	324,912,125	418,613,976	
Oil, NGL, & Condensate (barrels)	70,438,963	53,482,636	35,133,596	
Total Proved Reserves (Mcf equivalent)	749,365,449	645,807,939	629,415,552	
Production (Mcf equivalent)(4)	49,752,346	44,791,202	42,356,705	
Average Sales Price				
Natural Gas (per Mcf)	$2.30	$4.23	$4.24	
Oil (per barrel)	$20.88	$22.64	$29.35	

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

$2.68	$2.57	$1.77	$1.93	$1.96	$1.90
$17.59	$19.82	$15.66	$14.35	$15.10	$17.19

Item 7. 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 three years, we have emphasized adding reserves through drilling activity, while adding reserves through strategic purchases of producing properties when oil and gas prices were at lower levels and other market conditions were appropriate. We used this flexible strategy of employing both drilling and acquisitions to add more reserves than we depleted through production during this period.

Proved Oil and Gas Reserves. At year-end 2002, our total proved reserves were 749.4 Bcfe with a PV-10 Value of $1.2 billion. In 2002, our proved natural gas reserves increased 1.8 Bcf, or 1%, while our proved oil reserves increased 17.0 MMBbl, or 32%, for a total equivalent increase of 103.6 Bcfe, or 16%. In 2001, our proved natural gas reserves decreased by 93.7 Bcf, or 22%, while our proved oil reserves increased by 18.3 MMBbl, or 52%, for a total equivalent increase of 16.4 Bcfe, or 3%. We added reserves in 2002 through both our drilling activity and through purchases of minerals in place. Through drilling we added 83.9 Bcfe (15.9 Bcfe of which came from New Zealand) of proved reserves in 2002, 105.8 Bcfe (17.4 Bcfe of which came from New Zealand) in 2001, and 184.7 Bcfe (122.5 Bcfe of which came from New Zealand) in 2000. Through acquisitions we added 74.2 Bcfe of proved reserves in 2002, 54.6 Bcfe in 2001, and 39.7 Bcfe in 2000. At year-end 2002, 60% of our total proved reserves were proved developed, compared with 50% at year-end 2001 and 45% at year-end 2000.

Our total proved reserves quantities at year-end 2002 increased by 16% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 93% from the PV-10 Value at year-end 2001. Gas prices increased in 2002 to $3.49 per Mcf from $2.51 per Mcf at year-end 2001, compared to $9.86 per Mcf at year-end 2000. Oil prices increased in 2002 to $29.27 per barrel from $18.45 per Bbl at year-end 2001, compared to $24.62 in 2000. 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. 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 reserves revisions, solely attributed to the decrease in prices at year-end 2001. 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.

Contractual Commitments and Obligations

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

	2003	2004	2005	
Non-cancelable operating lease commitments	$2,190,363	$2,191,495	$523,755	$190
Capital commitments due to pipeline operators	933,666	---	---	
Senior Notes due 2009(1)	---	---	---	
Senior Notes due 2012(1)	---	---	---	
Credit Facility which expires in October 2005(2)	---	---	---	
	$3,124,029	$2,191,495	$523,755	$190

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Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. Worldwide supply disruptions, such as the reduction in crude oil production from Venezuela, together with perceived risks such as the threat of war between the United States and Iraq, along with other factors, have caused the price of oil to increase significantly in the first quarter of 2003 when compared to historical prices. Other factors such as actions taken by OPEC, worldwide economic conditions, and weather conditions can cause wide fluctuations in the price of oil. Natural gas prices have also increased significantly in the first quarter of 2003 when compared to historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause wide fluctuations in the price of natural gas. All of the above factors are beyond our control.

Liquidity and Capital Resources

During 2002, we principally relied upon cash provided by operating activities of $71.6 million, net proceeds from the issuance of long-term debt of $195.0 million, and net proceeds from our public stock offering of $30.5 million, less the repayment of bank borrowings of $134.0 million, to fund capital expenditures of $155.2 million. During 2001, we relied both upon internally generated cash flows of $139.9 million and upon additional borrowings from our bank credit facility of $123.4 million to fund capital expenditures of $275.1 million.

Net Cash Provided by Operating Activities. In 2002, net cash provided by our operating activities decreased by 49% to $71.6 million, as compared to $139.9 million in 2001 and $128.2 million in 2000. The 2002 decrease of $68.3 million was primarily due to a reduction of oil and gas sales of $40.0 million due to lower commodity prices and to an increase in interest of $10.6 million due to the higher debt balances and interest rates in 2002. The 2001 increase of $11.7 million was primarily due to a $14.0 million reduction 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.

Existing Credit Facilities. At December 31, 2002, we had no outstanding borrowings under our credit facility. Our credit facility at year-end 2002 consisted of a $300.0 million revolving line of credit with a $195.0 million borrowing base. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group in November 2002 with the $195.0 million borrowing base. 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, 2001, we had $134.0 million in outstanding borrowings under this facility.

Working Capital. Our working capital increased from a deficit of $36.5 million at December 31, 2001, to a deficit of $17.1 million at December 31, 2002. The increase was primarily due to reductions in payables to partnerships related to December 2001 property sales.

Capital Expenditures. In 2002, our capital expenditures of approximately $155.2 million included:

New Zealand activities of $95.2 million as follows:

- o $56.1 million, or 36%, on producing properties acquisitions, with approximately $51.7 million spent on the TAWN acquisition and the remainder for the cash portion of our Bligh and Antrim acquisitions;
- o $12.6 million, or 8%, on developmental drilling to further delineate the Rimu and Kauri areas;
- o $10.6 million, or 7%, on gas processing plants, principally the Rimu Production Station;
- o $10.3 million, or 7%, for exploratory drilling in the Rimu and Kauri areas;
- o $5.2 million, or 3%, on prospect costs, principally seismic and geological costs;
- o $0.4 million, or less than 1%, for fixed assets, principally computers and office furniture and fixtures.

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Domestic activities of $60.0 million as follows:

- o $34.4 million, or 22%, on developmental drilling;
- o $11.1 million, or 7%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- o $8.3 million, or 5%, on exploratory drilling;
- o $2.3 million, or 1%, for producing property acquisitions, including the purchase of property interests from partnerships managed by us;
- o $2.0 million, or 1%, on gas processing plants in the Brookeland and Masters Creek areas; o$1.1 million, or less than 1% on field compression facilities; and
- o $0.8 million, or less than 1%, for fixed assets.

In 2002, we participated in drilling 23 domestic development wells and seven domestic exploratory wells, of which 17 development wells and three exploratory wells were successful. In New Zealand three development wells and three exploratory wells were drilled. One of the development wells and one of the exploratory wells were dry.

We currently plan to spend $115 to $130 million in total capital expenditures in 2003, excluding acquisition costs and net of approximately $5 million to $15 million in non-core property dispositions. The budget for 2003 is largely dependent upon performance and pricing during the year. Domestic activities account for 85% of budgeted spending, primarily in the Lake Washington Area.

We believe that the anticipated internally generated cash flows for 2003, together with bank borrowings under our credit facility, will be sufficient to finance the costs associated with our currently budgeted 2003 capital expenditures. If other producing property acquisitions become attractive during 2003, we will explore the use of debt and/or equity offerings to fund such activity.

Our capital expenditures were approximately $275.1 million in 2001 and $173.3 million in 2000. During 2000, we used cash flows from operating activities 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. During 2001, we relied both upon internally generated cash flows of $139.9 million and upon additional borrowings of $123.4 million from our bank credit facility to fund capital expenditures of $275.1 million. Our capital expenditures in 2001 included:

Domestic activities of $224.3 million as follows:

- $120.6 million, or 44%, on developmental drilling;
- $40.5 million, or 15%, for producing property 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; o$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 property 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 successful. 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 was unsuccessful and one was temporarily abandoned.

Results of Operations

Revenues. Our revenues in 2002 decreased by 18% compared to revenues in 2001 due primarily to decreases in oil and gas prices. Partially offsetting the decrease in commodity prices received was the effect of an increase in production from our New Zealand and Lake Washington areas.

Oil and gas sales revenues in 2002 decreased by 22%, or $40.0 million, from the level of those revenues for 2001 even though our net sales volumes in 2002 increased by 11%, or 5.0 Bcfe, over net sales volumes in 2001. Average prices received for oil decreased to $20.88 per Bbl in 2002 from $22.64 per Bbl in 2001. Average gas prices received decreased to $2.30 per Mcf in 2002 from $4.23 per Mcf in 2001. The increase in production during the 2002 period is primarily from our New Zealand and Lake Washington areas.

In 2002, our $40.0 million decrease in oil and gas sales resulted from:

- Price variances that had a $59.0 million unfavorable impact on sales, of which $6.6 million was attributable to the 8% decrease in average oil prices received and $52.4 million was attributable to the 46% decrease in average gas prices received; and

- Volume variances that had a $19.0 million favorable impact on sales, with $16.2 million of increases coming from the 715,000 Bbl increase in oil sales volumes, and $2.8 million of the increases from the 0.7 Bcf increase in gas sales volumes.

Revenues in 2001 decreased by 4% compared to 2000 revenues. In 2001, oil and gas sales revenues decreased by 4%, or $8.0 million, from the level of those revenues in 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 an increase of $17.1 million 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.

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	2002	2001	2002	2001
AWP Olmos	$ 33.1	$ 56.1	10.9	13.0
Brookeland	11.9	25.1	4.1	6.5

Lake Washington	18.5	4.6	4.4	1.2
Masters Creek	32.3	62.3	9.7	15.3
Other	16.3	31.3	5.2	8.3
Total Domestic	$ 112.1	$ 179.4	34.3	44.3
Rimu/Kauri	4.0	1.8	1.5	0.5
TAWN	25.1	-	14.0	-
Total New Zealand	$ 29.1	$ 1.8	15.5	0.5
Total	$ 141.2	$ 181.2	49.8	44.8

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

	Net Sales Volume			Average Sales Pr	
	Oil and Condensate (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil and Condensate (Bbl)	G (
2000:					
First Qtr.	653	6.6	10.6	$27.35	$2
Second Qtr.	650	6.9	10.8	$27.55	$3
Third Qtr.	591	7.0	10.5	$30.68	$4
Fourth Qtr.	578	7.0	10.5	$32.26	$5
	2,472	27.5	42.4	$29.35	$4
2001:					
First Qtr.	603	6.7	10.3	$27.63	$6
Second Qtr.	691	7.1	11.3	$26.05	$4
Third Qtr.	813	6.8	11.7	$23.76	$2
Fourth Qtr.	948	5.9	11.5	$16.02	$2
	3,055	26.5	44.8	$22.64	$4
2002:					
First Qtr.	944	6.6	12.3	$16.10	$1
Second Qtr.	1,002	6.7	12.7	$20.98	$2
Third Qtr.	908	6.7	12.2	$23.05	$2
Fourth Qtr.	916	7.1	12.6	$23.55	$2
	3,770	27.1	49.8	$20.88	$2

In the table above, for 2002, natural gas liquids have been combined with oil and condensate for reporting purposes. The natural gas liquids production for 2002 was 1,174 MBbls, at an average price of $12.82 per barrel.

In March 2002, we received $7.5 million for our interest in the Samburg project located in Western Siberia, Russia as a result of the sale by a third party of its ownership in a Russia joint stock company that owned and operated the field. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all $10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a $7.3 million non-recurring gain on asset disposition in the first quarter of 2002. This activity was recorded in "Gain on asset disposition" in the accompanying consolidated statement of income.

During 2002, we recognized net losses of $191,701 relating to our derivative activities, as compared to net gains of $1,173,094 in 2001. In 2002, $7,889 of the losses were unrealized, while $16,784 of losses recognized in 2001 were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying income statement.

Revenues from our oil and gas sales comprised 94% of total revenues for 2002 and 99% of total revenues for both 2001 and 2000. Natural gas production made up 55% of our production volumes in 2002, 59% in 2001, and 65% in 2000.

Costs and Expenses. Our expenses in 2002 decreased $86.4 million, or 40%, compared to 2001 expenses. The majority of the decrease was due to the $98.9 million non-cash write-down of domestic oil and gas properties in 2001, offset by increases in operating costs in 2002 related to our increased activities in New Zealand. Our expenses in 2001 increased by $119.5 million, or 121%, compared to 2000 expenses. The majority of this increase was due to the non-cash write-down of domestic oil and gas properties in 2001.

Our general and administrative expenses, net in 2002 increased $2.4 million, or 29%, from the level of such expenses in 2001, while 2001 general and administrative expenses increased $2.6 million, or 47%, over 2000 levels. These increases reflect additional costs needed to run our increased activities in New Zealand, along with a reduction in reimbursement from partnerships we manage as these partnerships have liquidated. Our general and administrative expenses per Mcfe produced increased to $0.21 per Mcfe in 2002 from $0.18 per Mcfe in 2001 and $0.13 per Mcfe in 2000. The portion of supervision fees netted from general and administrative expenses was $3.0 million for 2002, $3.1 million for 2001, and $3.4 million for 2000.

Depreciation, depletion, and amortization of our assets, or DD&A, decreased $3.3 million, or 6%, in 2002 from 2001 levels, while 2001 DD&A increased $11.7 million, or 25%, from 2000 levels. Domestically, DD&A decreased $15.6 million due to decreased production in the 2002 period, the domestic non-cash write-down of oil and gas properties in the fourth quarter of 2001 that decreased our depletable oil and gas property base, and higher reserve volumes that were added primarily though our Lake Washington activities. In New Zealand, our production and the depletable oil and gas property base both increased in the 2002 period due primarily to the TAWN acquisition. The May 2002 commissioning of our Rimu Production Station also increased the depletable oil and gas property base. In 2001, the increase domestically was primarily due to additional dollars spent to add to our reserves and increased associated costs in an environment where demand for oil and gas services had increased compared to 2000, along with a 6% increase in production. Our DD&A rate per Mcfe of production was $1.13 in 2002, $1.33 in 2001, and $1.13 in 2000, reflecting variations in per unit cost of reserves additions.

Our production costs per Mcfe produced were $0.83 in 2002, $0.82 in 2001, and $0.69 in 2000. The portion of supervision fees netted from production costs was $2.0 million for 2002, $3.1 million for 2001, and $3.4 million for 2000. Our production costs in 2002 increased $4.8 million, or 13%, over such expenses in 2001, while those expenses in 2001 increased $7.5 million, or 26%, over 2000 costs. Overall, production costs increased in 2002 as our New Zealand activities increased, offsetting the domestic production costs decrease which mainly was due to a decrease in production volumes. 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 2001 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 oil and gas services has increased from the prior year.

Interest expense on our Senior Notes issued in July 1999, including amortization of debt issuance costs, totaled $13.2 million in 2002 and $13.1 million in both 2001 and 2000. Interest expense on our Senior Notes issued in April 2002, including amortization of debt issuance costs, totaled $13.5 million in 2002. Interest expense on our Convertible Notes due 2006, including amortization of debt issuance costs, totaled $7.4 million in 2000. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $3.6 million in 2002, $5.8 million in 2001, and $0.7 million in 2000. The total interest cost in 2002 was $30.3 million, of which $7.0 million was capitalized. The total interest cost in 2001 was $18.9 million, of which $6.3 million was capitalized. The 2000 total interest cost was $21.2 million, of which $5.2 million was capitalized. We capitalize that portion of interest related to our exploration, partnership, and foreign business development activities. The increase in interest expense in 2002 was attributed to the replacement of our bank borrowings in April 2002 with the Senior Notes that carry a higher interest rate. 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.

In the fourth quarter of 2001, we recognized 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 charges in the fourth quarter of 2001 for certain delinquent accounts receivable, the majority of which were 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 the 2001 consolidated statement of income.

In the fourth quarter of 2000, we recorded a $0.6 million loss on the early extinguishment of debt (net of taxes), as discussed in Note 4 to the 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 extraordinary item.

Net Income (Loss). Our net income in 2002 of $11.9 million was 153% higher and basic earnings per share ("Basic EPS") of $0.45 was 150% higher than our 2001 net loss of $(22.3) million and basic loss per share ("Basic EPS") of $(0.90). Our earnings per diluted share in 2002 of $0.45 was 150% higher than our 2001 loss per diluted share of $(0.90). These amounts increased in 2002 due to overall lower costs, as a non-cash write-down of oil and gas properties occurred in 2001 and not 2002, offset somewhat by lower revenue in 2002.

Our net loss in 2001 of $(22.3) million was 138% lower and basic loss per share of $(0.90) was 132% lower than our 2000 net income of $59.2 million and basic earnings per share of $2.79. Our earnings per diluted share in 2001 of $(0.90) was 136% lower than our 2000 earnings per diluted share of $2.51. These decreases reflected the effect of $101.0 million in charges in 2001 as described above.

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. 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 and equipment. Internal costs incurred that are directly identified with exploration, development and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. For the years 2002, 2001, and 2000, such internal costs capitalized totaled $10.7 million, $11.6 million, and $10.3 million, respectively. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

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

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.

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, net of salvage value, 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. Furniture, fixtures and other equipment are 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 current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using unhedged 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 the fourth quarter of 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.

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

Price-Risk Management Activities. We follow SFAS No. 133 which requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be reported in the balance sheet as either an asset or liability measured at its fair value. Special hedge accounting for qualifying hedges would allow the gains and losses on derivatives to offset related results on the hedged item in the income statements and would require that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of protection price floors and collars. We adopted SFAS No. 133 effective January 1, 2001. Accordingly, we marked our open contracts at December 31, 2000, to fair value at that date, resulting in a one-time net of taxes charge of $392,868, which was recorded as a Cumulative Effect of Change in Accounting Principle. During 2002 and 2001, we recognized net losses of $191,701 and net gains of $1,173,094 relating to our derivative activities. Approximately $7,889 of the losses recognized in 2002 were unrealized as the contracts were still open, while $16,784 of losses recognized in the comparative 2001 period were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2002, we had recorded $178,053, net of taxes of $100,155, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our collar transactions that were qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2002 was not material. We expect to reclassify all amounts held in "Other comprehensive loss" into the statement of income within the next six months.

As of December 31, 2002, we had entered into the cash flow hedge commodity derivative instruments set forth in the table below for our domestic oil and natural gas production for portions of 2003. When we entered into the following transactions they were designated as a hedge of the variability in cash flows associated with the forecasted sale of our oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are initially recorded in Other Comprehensive Income (Loss). When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are transferred from Other Comprehensive Income (Loss) and recorded in "Price-risk management and other, net" on the statement of income. The fair value of our derivatives are computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments is recognized on the balance sheet, in "Accounts payable and accrued liabilities," at December 31, 2002.

Crude Oil - Cash Flow Hedges		Collars		
Period and Type Of Contract	Volume in Bbls (000s)	Floors Weighted Average	Ceilings Weighted Average	December 31 Fair Va (000s
January 2003 - June 2003				
Participating Collar Contracts	360	$ 21.00		$
	144		$ 30.35	$
Total				$

Natural Gas - Cash Flow Hedges

Period and Type Of Contract	Volume in MMBtu (000s)	Collars Floors Weighted Average	Collars Ceilings Weighted Average	December 31 Fair Va (000s
January 2003 - June 2003				
Participating Collar Contracts	1,900	$ 3.00		$
	760		$ 5.27	$
Total				$

In January and February 2003, we entered into natural gas "floors" financial transactions covering contract periods April 2003 to October 2003. Notional volumes are 450,000 MMBtu per month at a weighted average floor price of $4.36 per MMBtu. In January 2003, we entered into crude oil "floors" financial transactions covering the contract periods of February to April 2003. Notional volumes are 625,000 barrels over the three-month period with a weighted average floor price of $26.39 per barrel. Also in February 2003, we entered into a crude oil "collar" financial transaction covering the contract period April 2003 to June 2003. Notional volumes are 120,000 barrels over the three-month period with a weighted average floor price of $25.25 per barrel and 48,000 barrels over the three-month period with a weighted average ceiling price of $33.08 per barrel.

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

Related-Party Transactions

We have been the operator of a number of properties owned by our affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships in 2002, 2001, and 2000 totaled approximately $300,000, $925,000, and $1,775,000, respectively, and are recorded as reductions of general and administrative expense and oil and gas production expense. We also have been reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $973,000, $3,140,000, and $4,465,000 in 2002, 2001, and 2000, respectively. In partnerships in which the limited partners voted to sell their remaining properties and liquidate their limited partnerships, we also have been reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately $510,000, $2,360,000, and $1,220,000 in 2002, 2001, and 2000, respectively.

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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.

Item 7A. 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 - At February 28, 2003, we had in place price floors in effect through the October 2003 contract month for natural gas and April 2003 for crude oil. The natural gas price floors cover notional volumes of 3,150,000 MMBtu, with a weighted average floor price of $4.36 per MMBtu. The crude oil price floors cover notional volumes of 400,000 barrels of oil, with a weighted average floor price of $26.13 per barrel.

- Participating Collars - At February 28, 2003, we had in place certain "collar" financial transactions in effect through the June 2003 contract month. The natural gas collars cover notional volumes of 1,100,000 MMBtu, with a floor price of $3.00 per MMBtu and ceiling prices ranging from $4.75 per MMBtu to $6.00 per MMBtu, plus 60% participation by us in prices realized above the ceiling. The crude oil collars cover notional volumes of 360,000 barrels of oil, with floor prices ranging from $21.00 to $26.00 per barrel and ceiling prices ranging from $29.04 to $35.05 per barrel, plus 60% participation by us in prices realized above these ceilings.

o New Zealand Gas Contracts - All of our gas production in New Zealand is sold under long-term, fixed-price contracts denominated in New Zealand dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

Interest Rate Risk. Our Senior Notes have a fixed interest rate, so consequently we are not exposed to cash flow risk from market interest rate changes on our Senior Notes. At December 31, 2002, we had no outstanding borrowings 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 43 basis points and would not impact 2003 cash flows 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, 2002 and 2001, 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 due 2009 was $129.0 million at December 31, 2002, and $126.5 million at December 31, 2001. Based upon quoted market prices as of the respective dates, the fair value of our Senior Notes due 2012 was $189.2 million at December 31, 2002. Our credit facility with the banks expires October 1, 2005. Our $125.0 million Senior Notes mature on August 1, 2009. Our $200.0 million Senior Notes mature on May 1, 2012.

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

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Item 8. Financial Statements and Supplementary Data

Report of Independent Auditors

Board of Directors and Stockholders
Swift Energy Company

We have audited the accompanying consolidated balance sheet of Swift Energy Company and subsidiaries as of December 31,2002, and the related consolidated statements of income, stockholders' equity and cash flows for the year then ended. 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 audit. The consolidated financial statements of Swift Energy Company and subsidiaries as of December 31, 2001, and for each of the two years in the period ended December 31, 2001, were audited by other auditors who have ceased operations and whose report dated February 18, 2002, expressed an unqualified opinion on those statements.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2002, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Houston, Texas
February 10, 2003

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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

Houston, Texas
February 18, 2002

NOTE: This is a copy of the report previously issued by Arthur Andersen LLP and has not been reissued.

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Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

	December 3
ASSETS	2002

Current Assets:	
Cash and cash equivalents	$ 3,816,107
Accounts receivable-	
Oil and gas sales	17,360,716
Associated limited partnerships and joint ventures	191,964
Joint interest owners	3,364,846
Other current assets	5,034,566
Total Current Assets	29,768,199
Property and Equipment:	
Oil and gas, using full-cost accounting	
Proved properties	1,150,633,802
Unproved properties	69,603,481
	1,220,237,283
Furniture, fixtures, and other equipment	9,595,944
	1,229,833,227
Less - Accumulated depreciation, depletion, and amortization	(504,323,773)
	725,509,454
Other Assets:	
Deferred income taxes	2,680,585
Deferred charges	9,047,621
	11,728,206
	$ 767,005,859
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current Liabilities:	
Accounts payable and accrued liabilities	$ 43,028,708
Payable to associated limited partnerships	91,126
Undistributed oil and gas revenues	3,764,350
Total Current Liabilities	46,884,184
Long-Term Debt	324,271,973
Deferred Income Taxes	30,776,518
Commitments and Contingencies	
Stockholders' Equity:	
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---
Common stock, $.01 par value, 85,000,000 shares authorized, 27,811,632 and 25,634,598 shares issued, and 27,201,509 and 24,795,564 shares outstanding, respectively	278,116
Additional paid-in capital	333,543,471
Treasury stock held, at cost, 610,123 and 839,034 shares, respectively	(8,749,922)
Retained earnings	40,179,572
Accumulated other comprehensive loss, net of income tax	(178,053)
	365,073,184
	$ 767,005,859

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Year Ended December	
	2002	2001
Revenues:		
Oil and gas sales	$ 141,195,713	$ 181,184,6
Fees from limited partnerships and joint ventures	67,173	427,5
Interest income	263,738	49,2
Gain on asset disposition	7,332,668	-
Price-risk management and other, net	1,110,519	2,145,9
	149,969,811	183,807,4
Costs and Expenses:		
General and administrative, net	10,564,849	8,186,6
Depreciation, depletion, and amortization	56,224,392	59,502,0
Oil and gas production	41,497,312	36,719,6
Interest expense, net	23,274,969	12,627,0
Other expenses	---	2,102,2
Write-down of oil and gas properties	---	98,862,2
	131,561,522	217,999,8
Income (Loss) Before Income Taxes, Extraordinary Item and Change in Accounting Principle	18,408,289	(34,192,3
Provision (Benefit) for Income Taxes	6,485,062	(12,237,4
Income (Loss) Before Extraordinary Item and Change In Accounting Principle	$ 11,923,227	$ (21,954,89
Extraordinary Loss on Early Extinguishment of Debt (net of taxes)	---	-
Cumulative Effect of Change in Accounting Principle (net of taxes)	---	392,8
Net Income (Loss)	$ 11,923,227	$ (22,347,7
Per Share Amounts-		
Basic: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ 0.45	$ (0.8
Extraordinary Loss	---	-
Change in Accounting Principle	---	(0.0
Net Income (Loss)	$ 0.45	$ (0.9

Diluted: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ 0.45	$ (0.8
Extraordinary Loss	---	-
Change in Accounting Principle	---	(0.0
Net Income (Loss)	$ 0.45	$ (0.9
Weighted Average Shares Outstanding	26,382,906	24,732,0

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)
Balance, December 31, 1999	$ 216,832	$ 191,092,851	$ (12,325,668)	$ (8,579,898)
Stock issued for benefit plans (46,632 shares)	310	297,060	224,469	-
Stock options exercised (543,450 shares)	5,434	4,316,446	-	-
Employee stock purchase plan (29,889 shares)	299	297,414	-	-
Subordinated notes conversion (3,164,644 shares)	31,646	97,392,952	-	-
Comprehensive income:				
Net income	-	-	-	59,184,008
Total comprehensive income	-	-	-	-
Balance, December 31, 2000	$ 254,521	$ 293,396,723	$ (12,101,199)	$ 50,604,110
Stock issued for benefit plans (11,945 shares)	72	354,973	68,408	-
Stock options exercised (152,915 shares)	1,529	1,942,634	-	-
Employee stock purchase plan (22,360 shares)	224	478,490	-	-
Comprehensive income:				
Net loss	-	-	-	(22,347,765)
Total comprehensive income	-	-	-	-
Balance, December 31, 2001	$ 256,346	$ 296,172,820	$ (12,032,791)	$ 28,256,345
Stock issued for benefit plans (38,149 shares)	292	617,960	127,795	-

Stock options exercised (112,995 shares)	1,130	1,206,413	-	-
Public stock offering (1,725,000 shares)	17,250	30,465,809	-	-
Employee stock purchase plan (9,801 shares)	98	122,343	-	-
Stock issued in acquisitions (520,000 shares)	3,000	4,958,126	3,155,074	-
Comprehensive income:				
Net income	-	-	-	11,923,227
Change in fair value of cash flow hedges, net of income tax	-	-	-	-
Total comprehensive income	-	-	-	-
Balance, December 31, 2002	$ 278,116	$ 333,543,471	$ (8,749,922)	$ 40,179,572

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries

	Year Ended Decembe	
	2002	2001
Cash Flows from Operating Activities:		
Net income (loss)	$ 11,923,227	$ (22,347,
Adjustments to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation, depletion, and amortization	56,224,392	59,502
Write-down of oil and gas properties	---	98,862
Deferred income taxes	6,482,724	(12,555
Gain on asset disposition	(7,332,668)	
Deferred revenue amortization related to production payment	---	
Other	270,770	509
Change in assets and liabilities-		
(Increase) decrease in accounts receivable, excluding income taxes receivable	283,419	16,207
Increase in accounts payable and accrued liabilities	3,174,450	12
(Increase) decrease in income taxes receivable	600,000	(306
Net Cash Provided by Operating Activities	71,626,314	139,884
Cash Flows from Investing Activities:		
Additions to property and equipment	(155,233,923)	(275,126,

Proceeds from the sale of property and equipment	13,256,674	9,274
Net cash received as operator of oil and gas properties	4,152,645	5,927
Net cash received (distributed) as operator of partnerships and joint ventures	(23,241,501)	(3,574
Other	(39,953)	(534,
Net Cash Used in Investing Activities	(161,106,058)	(264,033,
Cash Flows from Financing Activities:		
Proceeds from (payments of) long-term debt	200,000,000	
Net proceeds from (payments of) bank borrowings	(134,000,000)	123,400,
Net proceeds from issuances of common stock	31,409,200	1,633,
Payments of debt issuance costs	(6,262,435)	(721,
Net Cash Provided by (Used in) Financing Activities	91,146,765	124,311,
Net Increase (Decrease) in Cash and Cash Equivalents	$ 1,667,021	$ 162,
Cash and Cash Equivalents at Beginning of Year	2,149,086	1,986,
Cash and Cash Equivalents at End of Year	$ 3,816,107	$ 2,149
Supplemental Disclosures of Cash Flows Information:		
Cash paid during year for interest, net of amounts capitalized	$ 19,189,822	$ 12,207
Cash paid during year for income taxes	$ 2,500	$ 441
Non-Cash Financing Activity:		
Issuance of common stock in acquisitions	$ 8,116,200	$
Conversion of convertible notes to common stock	$ ---	$

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy Company (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 and inland waters 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.

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, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. For the years 2002, 2001, and 2000, such internal costs capitalized totaled $10.7 million, $11.6 million, and $10.3 million, respectively. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

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

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.

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, net of salvage value, 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. Furniture, fixtures and other equipment are 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 current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using unhedged 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 the fourth quarter of 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.

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

Oil and Gas Revenues. Oil and gas revenues are recognized, 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, 2002, 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 August 1999 of our 10.25% Senior Subordinated Notes (the "Senior Notes"), the September 2001 extension of our bank credit facility, and the public offering in April 2002 of our 9.375% Senior Subordinated Notes 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 due 2009 mature on August 1, 2009, and the balance of their issuance costs at December 31, 2002, was $2,686,678, net of accumulated amortization of $814,764. The issuance costs associated with our revolving credit facility, which closed in September 2001, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2002, was $986,957, net of accumulated amortization of $937,591. The Senior Notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2002, was $5,373,986, net of accumulated amortization of $244,349.

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 2002, we continue to serve as managing general partner for six remaining drilling partnerships, and during fiscal 2002 less than 1% 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 partnerships' properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. During 2002, an additional 65 production purchase partnerships were dissolved. The remaining six partnerships will continue to operate until their limited partners vote otherwise.

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Price-Risk Management Activities. The Company follows SFAS No. 133 which requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or a liability measured at its fair value. Special hedge accounting for qualifying hedges would allow the gains and losses on derivatives to offset related results on the hedged item in the income statements and would require that a company 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 price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of protection price floors and collars. 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 2002 and 2001, we recognized net losses of $191,701 and net gains of $1,173,094, respectively, relating to our derivative activities. Approximately $7,889 of the losses recognized in 2002 were unrealized as the contracts were still open, while $16,784 of losses recognized in the comparative 2001 period were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2002, the Company had recorded $178,053, net of taxes of $100,155, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our collar transactions that were qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2002 was not material. The Company expects to reclassify all amounts held in "Other comprehensive loss" into the statement of income within the next six months.

As of December 31, 2002, the Company had entered into certain "collar" financial transactions in effect through the June 2003 contract month. The natural gas collars cover notional volumes of 1,900,000 MMBtu for the price floors and 760,000 MMBtu for the price ceilings, with a weighted average floor price of $3.00 per MMBtu and a weighted average ceiling price of $5.27 per

MMBtu. The crude oil collars cover notional volumes of 360,000 barrels for the price floors and 144,000 barrels for the price ceilings, with a weighted average floor price of $21.00 per barrel and a weighted average ceiling price of $30.35 per barrel. When the Company entered into the following transactions they were designated as a hedge of the variability in cash flows associated with the forecasted sale of its oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are initially recorded in Other Comprehensive Income (Loss). When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are transferred from Other Comprehensive Income (Loss) and recorded in "Price-risk management and other, net" on the income statement. The fair value of our derivatives are computed using the Black- Scholes option pricing model and are periodically verified against quotes from brokers. At December 31, 2002, the fair value of the natural gas collars was a liability of $0.1 million and the fair value of our crude oil collars was a liability of $0.2 million. These instruments are recognized on the balance sheet in "Accounts payable and accrued liabilities" at December 31, 2002.

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 2002, oil and gas sales to Eastex Crude Company were $25.4 million, or 18.0% of oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were $14.6 million, or 10.3% of oil and gas sales. 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. 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.

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

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2002 and 2001, and were determined based upon variable 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 due 2009 were $129.0 million and $126.5 million at December 31, 2002 and 2001, respectively. Based upon quoted market prices as of December 31, 2002, the fair value of our Senior Notes due 2012 was $189.2 million. The carrying value of our Senior Notes due 2009 was $124.3 million and $124.2 million at December 31, 2002 and 2001, respectively. The carrying value of our Senior Notes due 2012 was $200.0 million at December 31, 2002.

Stock Based Compensation. We have three stock-based compensation plans, which are described more fully in Note 6. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of the grant. 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:

		2002	2001	2000
Net Income (Loss):	As Reported	$11,923,227	$(22,347,765)	$59,184,0
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(4,451,799)	(4,284,859)	(2,652,34
	Pro Forma	$7,471,428	$(26,632,624)	$56,531,6
Basic EPS:	As Reported	$.45	$(0.90)	$2.
	Pro Forma	$.28	$(1.08)	$2.
Diluted EPS:	As Reported	$.45	$(0.90)	$2.
	Pro Forma	$.27	$(1.08)	$2.

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions in 2002, 2001, and 2000, respectively: no dividend yield; expected volatility factors of 73.72%, 46.9%, and 46.7%; risk-free interest rates of 4.74%, 5.24%, and 6.61%; and expected lives of 7.4, 7.3, and 6.7 years.

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. 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. The Company has completed its assessment of SFAS No. 143. At January 1, 2003, we estimate that the present value of our future Asset Retirement Obligation ("ARO") for oil and gas properties and related equipment is approximately $8.9 million. We estimate that the cumulative effect of change in accounting principle, due to the adoption of SFAS No. 143, will be a loss of $6.8 million, or a loss of $4.4 million net of taxes. This cumulative effect of change in accounting principle will be a non-cash charge to net income in the first quarter of 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 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. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2002 and 2001 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, 2002, 2001, and 2000:

	2002			2001		
	Net Income	Shares	Per Share Amount	Net Loss	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$11,923,227	26,382,90	$ 0.45	$ (22,347,765)	24,732,099	$ (0.90)
Dilutive Securities:						
6.25% Convertible Notes	--	--		--	--	
Stock Options	--	372,700		--	--	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$11,923,227	26,755,60	$ 0.45	$ (22,347,765	24,732,099	$ (0.90)

3. Provision for Income Taxes

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

	Year Ended December 31,		
	2002	2001	2000
Current	$ 2,338	$ 114,611	$ (29,000)
Deferred	6,482,724	(12,352,047)	33,294,480
Total	$ 6,485,062	$ (12,237,436)	$ 33,265,480

There are differences between income taxes computed using the federal statutory rate (35% for 2002, 2001, and 2000) and our effective income tax rates (35.2%, 35.8%, and 35.7% for 2002, 2001, and 2000, respectively), primarily as the result of state income taxes, foreign income taxes, and in 2002 a currency exchange rate gain on the net foreign deferred tax asset. New Zealand's statutory rate and effective tax rate are 33%. We have not computed any provision for U.S. taxes on the undistributed earnings of our New Zealand subsidiaries as management intends to permanently reinvest such earnings. The undistributed earnings of the New Zealand subsidiaries were $8,175,013 and $1,234,919 for 2002 and 2001, respectively. Upon distribution of these earnings in the form of dividends or otherwise, we may be subject to U.S. income taxes and New Zealand withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings. Presently, there are no foreign tax credits available to reduce the U.S. taxes on such amounts if repatriated. Reconciliations of income taxes computed using the statutory rate to the effective income tax rates are as follows:

	2002	2001	
Income taxes computed at U.S. statutory rate	$ 6,442,901	$ (11,967,317)	$ 3
State tax provisions, net of federal benefits	298,933	(279,875)	
Effect of foreign operations	(163,500)	(24,698)	
Currency translation gain on foreign tax asset	(208,688)	---	
Other, net	115,416	34,454	
Provision (benefit) for income taxes	$ 6,485,062	$ (12,237,436)	$ 3

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2002 and 2001, were as follows:

	2002	
Long-term deferred tax assets:		
Alternative minimum tax credits (Domestic)	(1,979,399)	($1
Carryover items (Domestic)	(51,174,237)	(18
Acquired deferred tax asset (Foreign)	(4,753,044)	
Carryover Items (Foreign)	(19,494,129)	
Total long-term deferred tax assets	(77,400,809)	(20
Long-term deferred tax liabilities		
U.S. oil and gas properties	83,361,520	4
Foreign oil and gas properties	21,566,588	
Other	568,634	
Total long-term deferred tax liability	105,496,742	48
Net long-term deferred tax liability	$28,095,933	$27

The tax basis of the assets of Southern NZ on the acquisition date exceeded the cash purchase price paid by SENZ to acquire this entity. To account for the future tax benefits of this additional basis, SENZ recorded a deferred tax asset of $4,944,786. Additionally, the Company recognized a currency exchange rate gain, primarily attributable to this acquired asset, in the amount of $632,389. The asset is being amortized over the period in which the tax amortization is deducted. The remaining asset value at December 31, 2002, is $4,753,044, of which $950,609 will be amortized in 2003. The total foreign carryover asset amount is $19,494,129, of which $7,807,407 is expected to reverse in 2003. The asset is attributable to cumulative New Zealand net operating losses with a $U.S. equivalent value of $59,073,129 (using the December 31, 2002, exchange rate) multiplied by the New Zealand tax rate of 33%. These net operating losses include the costs of drilling oil and gas wells classified as exploratory. Under New Zealand tax rules, such costs are deductible at the time the well is drilled, but are "clawed back" into revenue if and when the well establishes commercial production. After the clawback, the costs are then amortized as development expenditures. This clawback is expected to occur in 2003, but should be absorbed by the cumulative excess of tax amortization over book depreciation, depletion, and amortization. New Zealand tax net operating losses do not expire.

At December 31, 2002, the Company had alternative minimum tax credits of $1,979,399 that carry forward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the related tentative minimum tax otherwise due.

The domestic deferred tax carryover items are attributable to expected future tax benefits in the amounts of $43,290,193 for federal net operating losses, $1,291,637 for State of Louisiana net operating losses, $6,574,726 for capital losses, and other items totaling $17,681. At December 31, 2002, cumulative federal net operating losses were $124 million, which will expire between 2018 and 2022. Louisiana net operating losses total $37 million and will expire between 2013 and 2017.

The Company has not recorded any valuation allowance against the deferred tax assets attributable to net operating loss carryovers at December 31, 2002 and 2001, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts.

In 2002 we recognized a capital loss of approximately $18.2 million as the result of the liquidation of our partnerships. This loss can only be utilized to offset capital gains and will expire in 2007. The Company plans to continue selling, in the ordinary course of business, a number of oil and gas properties over the next few years in order to optimize its portfolio of non-core oil and gas properties. To generate gains from these dispositions that can absorb the capital loss carryforward, the sales proceeds must exceed the Company's total investment in the properties before depreciation, depletion, and IDC deductions and amortization. Company management has identified several qualified properties to sell which have estimated current market values in excess of the total original costs. Management believes that it is more likely than not that the Company will fully utilize the capital loss carryover. If the Company is unable to complete the sale of these properties at the prices it has estimated to be the fair market value, then a significant portion of the capital loss carryover could expire before it is utilized.

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4. Long-Term Debt

Our long-term debt as of December 31, 2002 and 2001, is as follows:

	2002	2001
Bank Borrowings	$ ---	$ 134,000,000
Senior Notes due 2009	124,271,973	124,197,128
Senior Notes due 2012	200,000,000	---
Long-Term Debt	$ 324,271,973	$ 258,197,128

Bank Borrowings. At December 31, 2002, we had no outstanding borrowings under our $300.0 million credit facility with a syndicate of nine banks which has a borrowing base of $195.0 million and expires in October 2005. At December 31, 2001, we had borrowings of $134.0 million under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.25% at December 31, 2002) 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%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of

$15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to 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. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two active New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group in November 2002 with the same $195.0 million borrowing base. The next scheduled borrowing base review is in May 2003.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $3,618,570 in 2002, $5,833,564 in 2001, and $654,936 in 2000. The amount of commitment fees included in interest expense was $569,773, $306,663, and $284,633 in 2002, 2001, and 2000, respectively.

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.

Senior Notes Due 2009. Our Senior Notes due 2009 consist of $125.0 million of 10.25% Senior Subordinated Notes due August 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. 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. We are currently in compliance with the provisions of the indenture governing the Senior Notes.

Interest expense on the Senior Notes due 2009, including amortization of debt issuance costs and discount, totaled $13,156,973 in 2002, $13,123,052 in 2001, and $13,092,127 in 2000.

Senior Notes Due 2012. Our Senior Notes due 2012 at December 31, 2002, consist of $200,000,000 of 9.375% Senior Subordinated Notes due May 2012. The Senior Notes were issued on April 11, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank debt. Interest on the Senior Notes is payable semiannually on May 1 and November 1, with the first interest payment on November 1, 2002. On or after May 1, 2007, the Senior Notes are redeemable for cash at the option of Swift, with certain restrictions, at 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we may redeem up to 33.33% of the Senior Notes with the proceeds of qualified offerings of our equity at 109.375% 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. We are currently in compliance with the provisions of the indenture governing the Senior Notes.

Interest expense on the Senior Notes due 2012, including amortization of debt issuance costs and discount, totaled $13,525,599 in 2002.

We have capitalized interest in the amount of $7,000,000, $6,300,000, and $5,000,000 in 2002, 2001, and 2000, respectively.

5. Commitments and Contingencies

Total rental and lease expenses were $1,923,451 in 2002, $1,322,611 in 2001, and $1,255,474 in 2000. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $2,190,363 for 2003, $2,191,495 for 2004, $523,755 for 2005, $190,676 for 2006, $190,676 in 2007 and $186,834 thereafter or $5,473,799 in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas, and in New Zealand.

In the ordinary course of business, we have entered into agreements with pipeline operators that require us to contribute a portion of the pipeline construction cost in the event certain transportation volumes are not met. We have $933,666 accrued in "Accounts payable and accrued liabilities" at December 31, 2002, on the accompanying balance sheet related to these commitments.

As of December 31, 2002, we were the managing general partner of six 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.

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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. 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.

During the first quarter of 2002, we issued 1.725 million shares of common stock at a price of $18.25 per share. Gross proceeds from this offering were $31,481,250, with issuance costs of $998,191.

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 Stock Option Plan solely for our independent directors. In addition, we have an employee stock purchase plan.

Under the 2001 plan, incentive stock options and other options and awards may be granted to employees to purchase shares of common stock. Under the 1990 non-qualified plan, non-employee members of our board of directors are automatically granted options to purchase shares of common stock on a formula basis. Both plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Unless otherwise provided, options become exercisable for 20% of the shares on the first anniversary of the grant of the option and are exercisable for an additional 20% per year thereafter. Options granted 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 9,801 shares at a price of $12.47 in 2002, 22,360 shares at a price of $21.41 in 2001, and 29,889 shares at a price range of $8.40 to $10.57 in 2000. The estimated weighted average fair value of shares issued under this plan, as determined using the Black-Scholes option-pricing model, was $1.92 in 2002, $8.19 in 2001, and $4.25 in 2000. As of December 31, 2002, 352,627 shares remained available for issuance under this plan. There are no charges or credits to income in connection with this plan.

The following is a summary of our stock options under these plans as of December 31, 2002, 2001, and 2000:

	2002		2001	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,639,504	$ 17.44	2,076,593	$ 11.70
Options granted	585,055	$ 12.32	747,073	$ 31.51
Options canceled	(84,254)	$ 23.37	(31,247)	$ 14.09
Options exercised	(121,800)	$ 8.61	(152,915)	$ 8.69
Options outstanding, end of period	3,018,505	$ 16.64	2,639,504	$ 17.44
Options exercisable, end of period	1,480,490	$ 13.71	1,181,141	$ 11.49
Options available for future grant, end of period	419,845		1,155,057	

Estimated weighted average fair value per share of options granted during the year	$9.55	$20.68

The following table summarizes information about stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/02	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable At 12/31/02	Wtd. Avg. Exercise Price
$ 5.00 to $16.99	2,018,767	6.2	$ 10.32	1,126,267	$ 9.31
$17.00 to $28.99	272,480	5.4	$ 23.01	183,625	$ 23.52
$29.00 to $41.00	727,258	8.1	$ 31.82	170,598	$ 32.18
$ 5.00 to $41.00	3,018,505	6.6	$ 16.64	1,480,490	$ 13.71

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, 2002, 2001, and 2000, 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 $603,000, $558,000, and $483,000 for the years ended December 31, 2002, 2001, and 2000, respectively. The contributions in 2002 and 2001 were made all in common stock, while the 2000 contribution was made half in common stock and half in cash. The shares of common stock contributed to the 401(k) savings plan totaled 64,490, 28,798, and 7,175 shares for the 2002, 2001, and 2000 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, 2002, 610,123 shares remain in treasury (net of 317,651 shares used to fund ESOP, 401(k) contributions and acquisitions) with a total cost of $8,749,922 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, accordingly, charge these entities operating fees. The operating fees charged to the partnerships in 2002, 2001, and 2000 totaled approximately $300,000, $925,000, and $1,775,000, respectively, and are recorded as reductions in general and administrative expense and oil and gas production expense. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $973,000, $3,140,000, and $4,465,000 in 2002, 2001, and 2000, 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 $510,000, $2,360,000, and $1,220,000 in 2002, 2001, and 2000, respectively.

8. Foreign Activities

As of December 31, 2002, our gross capitalized oil and gas property costs in New Zealand totaled approximately $172.8 million. Approximately $145.0 million have been included in the proved properties portion of our oil and gas properties while $27.8 million is included as unproved properties. Our functional currency in New Zealand is the U.S. dollar.

9. Acquisitions and Dispositions

New Zealand

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

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

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

Russia

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

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Supplemental Information (Unaudited)

Swift Energy Company and Subsidiaries

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

	Total	Domestic
December 31, 2002:		
Proved oil and gas properties	$ 1,150,633,802	$ 1,005,583,492
Unproved oil and gas properties	69,603,481	41,850,890
	1,220,237,283	1,047,434,382
Accumulated depreciation, depletion, and amortization	(498,619,342)	(485,289,654
Net capitalized costs	$ 721,617,941	$ 562,144,728
December 31, 2001:		
Proved oil and gas properties	$ 974,698,428	$ 929,172,460
Unproved oil and gas properties	95,943,163	57,096,694
	1,070,641,591	986,269,154
Accumulated depreciation, depletion, and amortization	(442,337,531)	(442,166,052
Net capitalized costs	$ 628,304,060	$ 544,103,102

Of the $41,850,890 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2002, excluded from the amortizable base, $10,041,167 was incurred in 2002, $16,553,117 was incurred in 2001, $7,068,192 was incurred in 2000, and $8,188,414 was incurred in prior years. When we are in an active drilling mode, we evaluate the majority of these unproved costs within a two to four year time frame.

Of the $27,752,591 of net New Zealand unproved property costs at December 31, 2002, excluded from the amortizable base, $18,392,660 was incurred in 2002, $2,717,517 was incurred in 2001, $4,427,033 was incurred in 2000, and $2,215,381 was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there within a two to four year time frame.

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

	Year Ended December 31	
	Total	Domestic
Acquisition of proved properties	$ 64,229,283	$ 5,415,932
Lease acquisitions(1)	16,009,939	10,789,876
Exploration	18,395,335	7,571,215
Development	47,407,087	40,366,378
Total acquisition, exploration, and development(2)	$ 146,041,644	$ 64,143,401
Processing plants	$ 7,845,520	$ 1,313,299
Field compression facilities	2,251,247	2,251,247
Total plants and facilities	$ 10,096,767	$ 3,564,546
Total costs incurred	$ 156,138,411	$ 67,707,947

	Year Ended December 31	
	Total	Domestic
Acquisition of proved properties	$ 41,286,539	$ 40,491,203
Lease acquisitions1	31,225,493	25,688,068
Exploration	41,981,536	35,944,405
Development	132,246,713	112,597,856
Total acquisition, exploration, and development(2)	$ 246,740,281	$ 214,721,532
Processing plants	$ 23,331,095	$ 817,454
Field compression facilities	319,703	319,703

Total plants and facilities	$ 23,650,798	$ 1,137,157
Total costs incurred	$ 270,391,079	$ 215,858,689

	Year Ended December 31	
	Total	Domestic
Acquisition of proved properties	$ 34,191,883	$ 34,191,883
Lease acquisitions1	20,842,103	16,315,749
Exploration	20,150,834	18,524,883
Development	104,083,409	93,931,500
Total acquisition, exploration, and development 2	$ 179,268,229	$ 162,964,015
Processing plants	$ 1,819,464	$ 755,119
Field compression facilities	203,789	203,789
Total plants and facilities	$ 2,023,253	$ 958,908
Total costs incurred	$ 181,291,482	$ 163,922,923

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

	Year Ended December 31, 2002		
	Total	Domestic	New Zea
Oil and gas sales	$ 141,195,713	$ 112,065,003	$ 29,1
Oil and gas production costs	(41,497,312)	(33,088,958)	(8,4
Depreciation and depletion	(55,254,467)	(42,807,364)	(12,4
	44,443,934	36,168,681	8,2
Provision for income taxes	15,860,064	13,129,231	2,7
Results of producing activities	$ 28,583,870	$ 23,039,450	$ 5,5
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.11	$ 1.25	$

	Year Ended December 31, 2001		
	Total	Domestic	New Zea
Oil and gas sales	$ 181,184,635	$ 179,360,844	$ 1,8
Oil and gas production costs	(36,719,609)	(36,554,418)	(1

Depreciation and depletion	(58,589,116)	(58,417,637)	(1
Write-down of oil and gas properties	(98,862,247)	(98,862,247)	
	(12,986,337)	(14,473,458)	1,
Provision (benefit) for income taxes	$ (4,647,810)	(5,138,560)	
Results of producing activities	(8,338,527)	$ (9,334,898)	$
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.31	1.32	

	Year Ended December 31, 2000		
	Total	Domestic	New Zea
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 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	$

These results of operations do not include the effects of our hedging activities.

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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 7, 2003, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2002, 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	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NG and Condensa (Bbls)
Proved reserves as of December 31, 1999(1)	329,959,750	20,806,263	329,959,750	20,806,
Revisions of previous estimates(2)	(4,300,787)	(455,606)	(4,300,787)	(455,

Purchases of minerals in place	26,567,925	2,196,547	26,567,925	2,196,
Sales of minerals in place	(363,262)	(76,288)	(363,262)	(76,
Extensions, discoveries, and other additions	93,869,841	15,134,694	38,556,364	3,943,
Production3	(27,119,491)	(2,472,014)	(27,119,491)	(2,472,
Proved reserves as of December 31, 2000	418,613,976	35,133,596	363,300,499	23,942,
Revisions of previous estimates(2)	(122,127,541)	5,621,556	(101,693,477)	8,460,
Purchases of minerals in place	10,038,803	7,430,591	10,038,803	7,430,
Sales of minerals in place	(7,508,064)	(555,586)	(7,508,064)	(555,
Extensions, discoveries, and other additions	52,353,909	8,907,852	50,810,697	6,257,
Production	(26,458,958)	(3,055,373)	(26,458,958)	(2,971,
Proved reserves as of December 31, 2001	324,912,125	53,482,636	288,489,500	42,564,
Revisions of previous estimates(2)	(29,972,714)	5,298,439	(29,470,419)	8,675,
Purchases of minerals in place	51,940,044	3,711,948	226,245	24,
Sales of minerals in place	(3,839,124)	(464,490)	(3,839,124)	(464,
Extensions, discoveries, and other additions	10,822,919	12,180,558	197,919	11,304,
Production	(27,131,578)	(3,770,128)	(15,780,059)	(3,074,
Proved reserves as of December 31, 2002	326,731,672	70,438,963	239,824,062	59,029,
Proved developed reserves:				
December 31, 1999	174,046,096	8,437,299	174,046,096	8,437,
December 31, 2000	215,169,833	10,980,196	215,169,833	10,980,
December 31, 2001	181,651,578	23,759,574	167,401,736	20,393,
December 31, 2002(4)	233,514,572	35,928,395	149,731,562	26,530,

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,	
	Total	Domestic
Future gross revenues	$ 2,990,669,570	$ 2,578,435,576
Future production costs	(720,599,745)	(612,094,088)
Future development costs	(224,792,520)	(208,492,520)
Future net cash flows before income taxes	2,045,277,305	1,757,848,968
Future income taxes	(599,195,484)	(512,966,321)
Future net cash flows after income taxes	1,446,081,821	1,244,882,647
Discount at 10% per annum	(609,212,030)	(540,375,347)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 836,869,791	$ 704,507,300

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 1,706,475,138	$ 1,485,480,927
Future production costs	(483,588,857)	(436,141,429)
Future development costs	(198,172,628)	(185,347,628)
Future net cash flows before income taxes	1,024,713,653	863,991,870
Future income taxes	(261,635,331)	(208,726,729)
Future net cash flows after income taxes	763,078,322	655,265,141
Discount at 10% per annum	(308,520,417)	(274,882,174)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 454,557,905	$ 380,382,967

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 4,995,951,799	$ 4,737,560,630
Future production costs	(817,127,348)	(807,436,139)
Future development costs	(204,620,116)	(180,320,116)
Future net cash flows before income taxes	3,974,204,335	3,749,804,375
Future income taxes	(1,321,061,952)	(1,243,731,594)
Future net cash flows after income taxes	2,653,142,383	2,506,072,781
Discount at 10% per annum	(1,075,183,917)	(1,017,995,158)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,577,958,466	$ 1,488,077,623

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.

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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, net of salvage value, based on year-end cost estimates and the estimated effect of future income taxes.

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

tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and gas prices for each period and do not include the effects of our hedging activities. 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,		
	2002	2001	
Beginning balance	$ 454,557,905	$ 1,577,958,466	$ 4
Revisions to reserves proved in prior years--			
Net changes in prices, production costs, and future development costs	373,890,614	(1,692,627,074)	1,
Net changes due to revisions in quantity estimates	2,582,633	(93,669,181)	
Accretion of discount	60,298,619	231,325,481	
Other	(88,675,455)	(204,768,815)	(
Total revisions	348,096,411	(1,759,739,589)	1,
New field discoveries and extensions, net of future production and development costs	190,461,371	110,213,160	
Purchases of minerals in place	76,538,437	39,544,163	
Sales of minerals in place	(5,769,642)	(50,131,970)	
Sales of oil and gas produced, net of production costs	(99,698,403)	(144,262,145)	(
Previously estimated development costs incurred	48,752,814	94,107,760	
Net change in income taxes	(176,069,102)	586,868,060	(
Net change in standardized measure of discounted future net cash flows	382,311,886	(1,123,400,561)	1,
Ending balance	$ 836,869,791	$ 454,557,905	$ 1,

Quarterly Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2001 and 2002:

	Revenues	Income/(Loss) Before Income Taxes, Extraordinary Item and Change in Accounting Principle(b)	Income/(Loss) Before Extraordinary Item and Change in Accounting Principle(b)	Net Income/(Loss)	Basoc EPS Income/(Loss) Before Extraordinary Item and Change In Accounting Principle(b)	Dilu Incom Be Extrao Item Chang Accoun Princip
2001:						
First Quarter	$ 62,392,014	$ 35,513,130	$ 22,719,653	$ 22,326,785	$ 0.92	$
Second Quarter	52,303,265	23,408,900	14,972,946	14,972,946	0.61	
Third Quarter	41,244,583	11,607,563	7,420,090	7,420,090	0.30	
Fourth Quarter	27,867,628	(104,721,926)	(67,067,586)	(67,067,586)	(2.71)	
Total	$183,807,490	$ (34,192,333)	(21,954,897)	$ (22,347,765)	$ (0.89)	$
2002:						
First Quarter(a)	$ 34,354,077	$ 4,674,075	$ 3,019,810	$ 3,019,810	$ 0.12	$
Second Quarter	38,570,269	5,518,886	3,584,092	3,584,092	0.13	
Third Quarter	36,570,809	2,933,350	1,947,006	1,947,006	0.07	
Fourth Quarter	40,474,656	5,281,978	3,372,319	3,372,319	0.12	
Total	$149,969,811	$ 18,408,289	$ 11,923,227	$ 11,923,227	$ 0.45	$

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We have had no changes in or disagreements with our independent accountants since our Board of Directors' June 12, 2002 appointment, based upon the recommendation of our Audit committee, of Ernst & Young LLP as Swift's independent auditors for the fiscal year ended December 31, 202, replacing Arthur Andersen LLP as our independent auditors. That change was reported by Swift in a Current Report on Form 8-K dated June 12, 2002, filed with the SEC on June 18, 2002.

A copy of the previously issued report dated February 18, 2002 of Arthur Andersen LLP on the consolidated financial statements of the Company as of and for the fiscal years ended December 31, 2000 and December 31, 2001 is included in this Form 10-K Report for the year ended December 31, 2002, but such previously issued report has not been reissued.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 13, 2003, annual shareholders' meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 13, 2003, annual shareholders' meeting is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information required under Item 12 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 13, 2003, annual shareholders' meeting is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The information required under Item 13 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 13, 2003, annual shareholders' meeting is incorporated herein by reference.

Item 14. Controls and Procedures

The Company's chief executive officer and chief financial officer have evaluated the Company's disclosure controls and procedures, as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934 (the "Exchange Act") as of a date within 90 days before the filing of this report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required under the Exchange Act to be disclosed in this report.

There were no significant changes in the Company's internal controls that could significantly affect such controls subsequent to the date of their evaluation.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) 1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 10, 2003, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

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3. Exhibits

3(a)(1)	Amended and Restated Articles of Incorporation of Swift Energy Company.
3(b)(12)	Second Amended and Restated Bylaws of Swift Energy Company, as amended thro
4(a).1(2)	Indenture dated as of July 29, 1999, between Swift Energy Company and Bank
4(a).2(3)	First Supplemental Indenture dated as of August 4, 1999, between Swift E including the form of 10.25% Senior Subordinated Notes due 2009.
4(a).3(4)	Indenture dated as of April 16, 2002, between Swift Energy Company and Bank
4(a).4(5)	First Supplemental Indenture dated as of April 16, 2002, between Swift E including the form of 9 3/8% Senior Subordinated Notes due 2012.
10.1(13)	Indemnity Agreement dated July 8, 1988, between Swift Energy Company and A. Earl Swift (plus schedule of other persons with whom Indemnity Agreements have been entered into).
10.2(6) +	Amended and Restated Swift Energy Company 1990 Nonqualified Stock Option Pl
10.5(7) +	Swift Energy Company 2001 Omnibus Stock Compensation Plan
10.6(8) +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift.
10.7(1) +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift.
10.8(1) +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Kitterman.
10.9(1) +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Vincent.
10.10(1)+	Amended and Restated Employment Agreement dated as of May 9, 2001 between D'Amico.
10.11(1)+	Employment Agreement dated as of May 9, 2001 between Swift Energy Company a
10.13(1)+	Amended and Restated Employment Agreement dated as of May 9, 2001 between Heckaman, Jr.
10.14(8)+	Fourth Amended and Restated Agreement and Release, by and between Swift En dated November 20, 2000.
10.15(9)	Amended and Restated Rights Agreement between Swift Energy and American Sto March 31, 1999.
10.16(10)	Amended and Restated Credit Agreement among Swift Energy Company and Bank CIBC Inc. as syndication agent and Credit Lyonnais New York Branch and S agents and the lenders signatory hereto dated September 28, 2001.
10.17(11)	First Amendment to Amended and Restated Credit Agreement, effective Jan Company, as Borrower, Bank One, NA as Administrative Agent, CIBC Inc. as New York Branch as Documentation Agent, Societe Generale as D Signatory Hereto and Banc One Capital Markets, Inc. as Sole Lead Arranger a

10.18(11)	Second Amendment to Amended and Restated Credit Agreement, effective April as Borrower, Bank One, NA as Administrative Agent, CIBC Inc. as Syndicatio National Association as Syndication Agent, Credit Lyonnais, New York Bran Generale as Documentation Agent and The Lenders Signatory Hereto and Banc Lead Arranger and Sole Book Runner.
12*	Swift Energy Company Ratio of Earnings to Fixed Charges.
21*	List of Subsidiaries of Swift Energy Company
23(a)*	The consent of H.J. Gruy and Associates, Inc.
23(b)*	Consent of Ernst & Young LLP as to incorporation by reference regardin Statements.
31(a)*	Certification of the Chief Executive Officer pursuant to Section 302 of the
31(b)*	Certification of the Chief Financial Officer pursuant to Section 302 of the
32*	Certification of Chief Executive Officer and Chief Financial Officer Sarbanes-Oxley Act of 2002.
99.1*	The summary of H.J. Gruy and Associates, Inc. report, dated February 7, 200

(b) No Reports on Form 8-K were filed during the last quarter of 2002.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant, Swift Energy Company, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SWIFT ENERGY COMPANY

By /s/ Terry E. Swift
Terry E. Swift
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant, Swift Energy Company, and in the capacities and on the dates indicated:

Signatures	Title	Date
/s/ A. Earl Swift A. Earl Swift	Chairman of the Board	April 16, 200
/s/ Terry E. Swift	Director	

Terry E. Swift	Chief Executive Officer President	April 16, 200
/s/ Alton D. Heckaman Jr. Alton D. Heckaman Jr.	Sr. Vice-President--Finance Principal Financial Officer	April 16, 200
/s/ David W. Wesson David W. Wesson	Controller Principal Accounting Officer	April 16, 20
/s/ Virgil N. Swift Virgil N. Swift	Director	April 16, 20
/s/ G. Robert Evans G. Robert Evans	Director	April 16, 20
/s/ Harold J. Withrow Harold J. Withrow	Director	April 16, 20

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SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

EXHIBITS

TO

FORM 10-K REPORT

FOR THE

YEAR ENDED DECEMBER 31, 2002

SWIFT ENERGY COMPANY

16825 NORTHCHASE DRIVE, SUITE 400

HOUSTON, TEXAS 77060

EXHIBITS

12	Swift Energy Company Ratio of Earnings to Fixed Charges.
21	Significant Subsidiaries.
23(a)	The consent of H.J. Gruy and Associates, Inc.
23(b)	The consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31(a)	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	The Summary of H.J. Gruy and Associates, Inc. report, dated February 7, 2003.