

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

Form 10-K

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

For the Fiscal Year Ended December 31, 2003

Commission File Number 1-8754

SWIFT ENERGY COMPANY

(Exact Name of Registrant as Specified in Its Charter)

Texas
(State of Incorporation)

74-2073055
(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:
Common Stock, par value \$.01 per share

Exchanges on Which Registered:
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 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 No

The aggregate market value of the voting stock held by non-affiliates at March 1, 2004 was approximately \$540,579,623.

The number of shares of common stock outstanding as of March 1, 2004 was 27,580,593 shares of common stock, \$.01 par value.

Documents Incorporated by Reference

Document

Incorporated as to

Notice and Proxy Statement for the Annual

Part III, Items 10, 11, 12, 13, and 14

Meeting of Shareholders to be held May 11, 2004

Form 10-K

Swift Energy Company and Subsidiaries

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(1) Incorporated by reference from Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 2004.

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, 2003, we had interests in 998 wells located domestically in four states, in federal offshore waters, and in New Zealand. We operated 870 of these wells representing 95% of our proved reserves. At year-end 2003, we had estimated proved reserves of 820.4 Bcfe, of which approximately 47% was crude oil, 41% natural gas, and 12% NGLs, and overall 59% was proved developed. Our proved reserves are concentrated 40% in Louisiana, 37% in Texas, 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 2003 Proved Reserves	% of 2003 Production
AWP Olmos	South Texas	26%	16%
Brookeland	East Texas	5%	7%
Lake Washington	South Louisiana	32%	23%
Masters Creek	Central Louisiana	8%	11%
Rimu/Kauri	New Zealand	15%	6%
TAWN	New Zealand	6%	30%
% of Total		92%	93%

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. Based on our total 2003 year-end proved reserves and total 2003 production, we calculated our average reserve life as 15.4 years.

We have increased our proved reserves to 820.4 Bcfe at year-end 2003 from 436.1 Bcfe at year-end 1998, which has resulted in the replacement of 266% 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 2003, were \$1.17, \$0.91, \$3.43, \$0.82, and \$1.21 per Mcfe. In 2003, we increased our proved reserves by 9.5%, which replaced 234% of our 2003 production. Our 2003 production increased by 7% in relation to 2002 production. We have increased our production to 53.2 Bcfe at year-end 2003 from 39.0 Bcfe at year-end 1998. Primarily due to increased production, this has resulted in average annual growth in net cash provided by operating activities of 15% per year from year-end 1998 to year-end 2003.

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 105.6 Bcfe of proved reserves through drilling in 2003 (36.1 Bcfe from New Zealand), 83.9 Bcfe in 2002 (15.9 Bcfe from New Zealand), and 105.8 Bcfe in 2001 (17.4 Bcfe from New Zealand). The 2003 additions were driven by the result of our development completion rate, as we successfully completed 53 of 63 domestic development wells, while five of eight domestic exploratory wells were successfully completed. In New Zealand we drilled three development wells and one exploratory well. Only one of these four wells, the exploratory well, was unsuccessful.

We have also added reserves through acquisitions. 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 price adjustments. 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. 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 146 transactions from 1979 to 2003, we have acquired approximately \$697.6 million of producing oil and gas properties on behalf of our co-investors and ourselves. We acquired, for our own account, approximately \$341.2 million of producing properties, with original proved reserves estimated at 469.0 Bcfe during this period. Our producing property acquisition expenditures in the past three years were \$1.9 million in 2003, \$64.2 million in 2002, and \$41.3 million in 2001. Our acquisition costs have averaged \$0.83 per Mcfe over this three-year period. Our acquisition costs in 2003 averaged \$3.99 per Mcfe and were made up of purchases of limited partner interests in several of the remaining partnerships we manage.

We currently plan to spend \$130 to \$150 million in total capital expenditures in 2004, excluding acquisition costs and net of approximately \$5 million to \$15 million in non-core property dispositions. As always, the budget for 2004 is dependent upon our performance and commodity pricing during the year. As currently planned, domestic activities account for 80% 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. Our primary goals for the next five years are to increase proved oil and gas reserves at an average rate of 5% to 10% per year and production at an average rate of 7% to 12% per year.

Balanced Approach to Adding Reserves

When we believe market conditions favor increasing reserves through acquisitions, we apply our considerable experience in evaluating and negotiating prospective acquisitions. We believe this balanced approach between acquisitions and drilling 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.

As both oil and natural gas prices were strong in 2003, carrying over from 2002, we focused our capital expenditures on drilling mainly in the Lake Washington area and south Texas domestically and in the Rimu/Kauri area in New Zealand. Our total capital expenditures in 2003 were \$144.5 million. Of this amount, \$68.9 million was spent on drilling in the United States, with \$57.0 million for development drilling and \$11.9 million for exploratory drilling. In New Zealand we spent \$17.4 million on drilling, with \$15.1 million for development drilling and \$2.3 for exploratory drilling. We also spent \$25.9 million for the construction of domestic production and surface facilities, mainly in our Lake Washington area. Our leasehold, seismic and geological costs of prospects, both in the United States and New Zealand, were \$17.8 million in 2003. The remaining capital expenditures of \$14.5 million were spent on gas processing plants, field compression facilities and furniture and fixtures, both in the United States and New Zealand. During 2003, we largely relied upon cash provided by operating activities of \$110.8 million, proceeds of bank borrowings of \$15.9 million, and proceeds from the sale of property and equipment of \$10.2 million to fund our capital expenditures.

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 from the 2001 level 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.

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. The value of this concentration is enhanced by us acting as the operator of 95% of our proved reserves at year-end 2003. Our operational control allows us to better manage production, control our expenses, allocate capital and time field development. We intend to continue acquiring 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 are able to apply our technical and operational experience to optimize our exploration and exploitation of such acquired properties.

- 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 reserves that can be developed in higher priced environments.

- 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. We have since drilled 17 wells in New Zealand since operations began in 1999. When we first acquired our interest in Masters Creek, Brookeland, and Lake Washington, these areas also had significant additional development potential, and are still viewed as such.

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. These facilities and pipelines 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 experience and current 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 experience 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 provides the 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, 2003, our long-term debt comprised approximately 46% of our total capitalization. At December 31, 2003, we had \$233.3 million of available borrowing capacity under our credit facility.

Domestic Core Operating Areas

AWP Olmos Area. As of December 31, 2003, we owned 27,900 net acres in the AWP Olmos Area in South Texas. We have extensive experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 66% gas. At year-end 2003, we owned interests in and operated 504 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 2003, we completed eight development wells in this area, performed four fracture extensions, and installed coiled tubing velocity strings in six wells. At year-end 2003, we had 124 proved undeveloped locations. Also in 2003, we purchased interests in the AWP Olmos area from partnerships we managed. Our planned 2004 capital expenditures in this area will focus on drilling 15 to 18 development wells.

Brookeland Area. As of December 31, 2003, we owned drilling and production rights in 72,516 net acres and 3,500 fee mineral acres in the Brookeland 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 56% oil and natural gas liquids. In 2003, we completed one development well in this area. At year-end 2003, we had 12 proved undeveloped locations in this area. Our planned 2004 capital expenditures in this area include drilling one development well.

Lake Washington Field. As of December 31, 2003, we owned drilling and production rights in 12,911 net acres in the Lake Washington Field. This area is located in Plaquemines Parish in South Louisiana. The reserves are approximately 94% oil and natural gas liquids. We acquired our 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 77 producing wells is gathered from three platforms located in water depths from 2 to 12 feet, with drilling and workover operations performed with barge rigs. In 2003, 52 development wells and six exploratory wells were drilled in the area; 42 development and five exploratory wells were completed. At year-end

2003, we had 82 proved undeveloped locations in this field. Our planned 2004 capital expenditures in this area include drilling 25 to 30 development wells and two to four exploratory wells.

Masters Creek Area. As of December 31, 2003, we owned drilling and production rights in 62,560 net acres and 91,994 fee mineral acres in the Masters Creek 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 71% oil and natural gas liquids. At year-end 2003, we had 12 proved undeveloped locations in the area. Our planned 2004 capital expenditures in this area include drilling one to two development wells.

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 identified as Garcia Ranch, which straddles the border of Kenedy County and Willacy County in the southern tip of Texas. Retaining a 65% working interest, we had three discoveries in the area in 2001 and 2002, one in the Rome prospect in Willacy County, one in the Siena prospect in Kenedy County and one in the Milan prospect in Kenedy county. In 2003, we participated in completing one well in the Milan prospect with a 33% working interest. Two exploratory wells drilled in this area during 2003 were not successful. We plan to participate in drilling up to five wells in 2004 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 exploratory well in this area in 2004, contingent upon finding a working interest partner.

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 another Woodbine prospect, the Jaguar prospect, located in Polk County. The Jaguar prospect may be drilled in 2004 if a working interest partner joins us for the project.

New Zealand Core Operating Areas

Our activity in New Zealand began in 1995. As of December 31, 2003, 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 (New Zealand) Exploration, Limited (Southern NZ), 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 sold a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale resulted 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. In 2003 this well was re-entered but was unsuccessful.

As of December 31, 2003, our gross capitalized oil and gas property costs in New Zealand totaled approximately \$205.3 million. Approximately \$169.5 million of our investment costs have been included in the proved properties portion of our oil and gas properties, while \$35.8 million is included as unproved properties. Our functional currency in New Zealand is the U.S. Dollar.

Natural gas prices are substantially lower in New Zealand as compared to domestic prices, due largely to the predominant supply from the Maui Field under long standing supply contracts. However, the Maui Field that in recent years has supplied over 70% of the nation's natural gas appears to have reached its peak sooner than anticipated, and its production is projected to decline sharply over the next few years and has begun to put upward pressure on natural gas prices in New Zealand.

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.

Kauri Area. During 2003, we completed three of four wells in the Kauri area. Two of these wells successfully targeted the Kauri Sand, the third was completed in the Manutahi Sand. We also fracture stimulated three Kauri Sand wells in 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. 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 exceeded the contract minimum during all of 2003.

Solution gas gathered from the Waihapa Production Station (“WPS”) flows to the Tariki Ahuroa gas plant (“TAG”). The current processing capacity per day of the WPS facility is up to 15,000 barrels of oil and 45 MMcf of natural gas. Processing capacity tests conducted following facility modifications completed in the third quarter of 2002 confirmed a 12% increase in the gas processing capacity of the TAG plant up to the 45 MMcf per day level. 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”), under which SPM purchases all of our New Zealand crude oil production, runs through the end of 2004. 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 for use at its Huntly Power Station, New Zealand's largest thermal power station.

New Zealand Emerging Growth Areas

The Tawa prospect is located northwest of the Rimu and Kauri areas in permit 38719. 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 our analysis of existing three-dimensional seismic data plus two-dimensional seismic data acquired during Swift surveys in 1997 and 2000. The Tawa prospect may also include a shallower prospect located on the southeast flank of the Tawa prospect. It was identified based upon the analysis of the two-dimensional seismic data we acquired in 2000.

Three prospects are located in the Company's TAWN area and are identified as the Waihapa Deep prospect, the Toko Deep prospect, and the Ahuroa Flank prospect. All three prospects will have the Kapuni group sands (the major reservoir in the basin) as their main target, but as these wells are drilled they will also pass through the Tariki sandstone and other major producers in the basin.

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 through an existing pre-emptive right under the joint operating agreement. Following the transaction, SENZ sold a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale resulted in SENZ holding a 50% working interest in this permit. We are the operator of the permit. Permit 38718 contains the Tuihu #1 exploratory well, which was drilled in 2001 and was temporarily abandoned. In 2003, this well was re-entered but was unsuccessful.

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, 2003, 2002, and 2001. 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 conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of production histories and other geological, economic, and engineering data provided by Swift. Where Gruy had material disagreements with Swift reserve estimates, we revised our estimates to be in agreement.

In accordance with Securities and Exchange Commission guidelines, estimates of future net revenues from our proved reserves and the PV-10 Value are made using oil and gas sales prices in effect as of the dates of such estimates adjusted for the effects of hedging and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end price and thus did not affect prices used in these calculations. Proved reserves as of December 31, 2003, were estimated based upon prices in effect at year-end. The weighted averages of such year-end prices domestically were \$5.53 per Mcf of natural gas, \$30.88 per barrel of oil, and \$21.81 per barrel of NGL, compared to \$4.23, \$29.36, and \$17.30 at year-end 2002 and \$2.68, \$18.51, and \$11.00 at year-end 2001, respectively. The weighted averages of such year-end 2003 prices for New Zealand were \$2.04 per Mcf of natural gas, \$26.78 per barrel of oil, and \$14.10 per barrel of NGL, compared to \$1.48, \$28.80, and \$12.24 in 2002 and \$1.18, \$18.25, and \$8.90 in 2001, respectively. The weighted averages of such year-end 2003 prices for all our reserves, both domestically and in New Zealand, were \$4.56 per Mcf of natural gas, \$30.16 per barrel of oil, and \$20.61 per barrel of NGL, compared to \$3.49, \$29.27, and \$16.54 in 2002 and \$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 its PV-10 Value. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in Supplemental Information to our Consolidated Financial Statements, which is calculated after provision for future income taxes.

Year Ended December 31, 2003

	Total	Domestic	New Zealand
Estimated Proved Oil and Gas Reserves			
Net natural gas reserves (Mcf):			
Proved developed	210,119,927	138,173,341	71,946,586
Proved undeveloped	125,684,935	104,147,935	21,537,000
Total	<u>335,804,862</u>	<u>242,321,276</u>	<u>93,483,586</u>
Net oil and NGL reserves (Bbl):			
Proved developed	45,525,366	38,767,983	6,757,383
Proved undeveloped	35,234,537	28,247,710	6,986,827
Total	<u>80,759,903</u>	<u>67,015,693</u>	<u>13,744,210</u>

Estimated Present Value of Proved Reserves

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

Proved developed	\$ 940,882,612	\$ 805,834,173	\$ 135,048,439
Proved undeveloped	597,912,185	517,485,024	80,427,161
Total	<u>\$ 1,538,794,797</u>	<u>\$ 1,323,319,197</u>	<u>\$ 215,475,600</u>

Year Ended December 31, 2002

	Total	Domestic	New Zealand
Estimated Proved Oil and Gas Reserves			
Net natural gas reserves (Mcf):			
Proved developed	233,514,572	149,731,562	83,783,010
Proved undeveloped	93,217,100	90,092,500	3,124,600
Total	<u>326,731,672</u>	<u>239,824,062</u>	<u>86,907,610</u>
Net oil and NGL reserves (Bbl):			
Proved developed	35,928,395	26,530,112	9,398,283
Proved undeveloped	34,510,568	32,499,528	2,011,040
Total	<u>70,438,963</u>	<u>59,029,640</u>	<u>11,409,323</u>

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	\$ 162,523,324
Proved undeveloped	481,833,151	456,632,145	25,201,006
Total	<u>\$ 1,161,189,323</u>	<u>\$ 973,464,993</u>	<u>\$ 187,724,330</u>

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

At year-end 2003, 59% of the proved reserves were developed reserves. At year-end 2002, 60% of proved reserves were developed. At year-end 2001, 50% 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 2003 increased by 9% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 33% from the PV-10 Value at year-end 2002. While our total proved reserves quantities, on an equivalent Bcfe basis, at year-end 2002 increased by 16% over reserves quantities in 2001, the PV-10 Value of those reserves increased 93% from the PV-10 Value at year-end 2001. The PV-10 Value increases in 2003 and 2002 were heavily influenced by higher prices at year-end 2003 as compared to year-end 2002 and year-end 2002 as compared to year-end 2001. Product prices for natural gas increased 31% during 2003, from \$3.49 per Mcf at year-end 2002 to \$4.56 at year-end 2003, while oil prices increased 3% between the same two dates, from \$29.27 to \$30.16 per barrel. Product prices for natural gas increased 39% during 2002, from \$2.51 per Mcf at December 31, 2001, to \$3.49 per Mcf 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, matched by a 25% decrease in the price of oil between the two dates, from \$24.62 to \$18.45 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 that voted to do so, our total gross well count decreased from 2001 levels. 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, 2003:			
Gross	397	560	957
Net	340.6	504.0	844.6
December 31, 2002:			
Gross	342	555	897
Net	278.9	479.8	758.7
December 31, 2001:			
Gross	396	786	1,182
Net	297.0	467.9	764.9

(1) Excludes 41 service wells in 2003, 35 service wells in 2002, and 48 service wells in 2001.

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, 2003:

	Developed (1)		Undeveloped (1)	
	Gross	Net	Gross	Net
Alabama	9,686.01	2,859.10	644.22	183.99
Louisiana	82,257.09	65,415.99	16,637.34	10,296.57
Mississippi	630.03	163.32	60.00	15.80
Texas	166,636.81	113,555.70	31,284.03	19,017.64
Wyoming	681.07	151.06	67,698.95	66,078.96
All other states	320.00	266.66	400.00	257.32
Offshore Louisiana	4,609.37	276.56	5,000.00	258.34
Offshore Texas	2,880.00	74.39	---	---
Total Domestic	<u>267,700.38</u>	<u>182,762.78</u>	<u>121,724.54</u>	<u>96,108.62</u>
New Zealand	7,600.00	7,181.70	162,422.37	124,766.10
Total	<u><u>275,300.38</u></u>	<u><u>189,944.48</u></u>	<u><u>284,146.91</u></u>	<u><u>220,874.72</u></u>

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

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2003:

Year	Type of Well	Gross Wells				Net Wells			
		Total	Producing	Dry	Temporarily Abandoned	Total	Producing	Dry	Temporarily Abandoned
2003	Exploratory-Domestic	8	5	3	--	7.3	5.0	2.3	--
	Development-Domestic	63	53	10	--	61.9	51.9	10.0	--
	Exploratory-New Zealand	1	--	1	--	0.5	--	0.5	--
	Development-New Zealand	3	3	--	--	3.0	3.0	--	--
2002	Exploratory-Domestic	7	3	4	--	5.0	2.3	2.7	--
	Development-Domestic	23	17	6	--	23.0	17.0	6.0	--
	Exploratory-New Zealand	3	2	1	--	2.2	2.0	0.2	--
	Development-New Zealand	3	2	1	--	3.0	2.0	1.0	--
2001	Exploratory-Domestic	11	6	5	--	6.2	4.0	2.2	--
	Development-Domestic	36	36	--	--	29.5	29.5	--	--
	Exploratory-New Zealand	2	--	1	1	1.1	--	0.9	0.2
	Development-New Zealand	4	2	2	--	3.6	1.8	1.8	--

Operations

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

Oil and gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator's direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or gas. The fees for these activities paid to us in 2003 totaled \$5.1 million and ranged from \$450 to \$2,107 per well per month.

Marketing of Production

Domestically, we typically sell our oil and gas production at market prices near the wellhead or at a central point after gathering and/or processing. 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. Shell, both domestically and in New Zealand, and Contact Energy in New Zealand each accounted for 10% or more of our total revenues during the year ended December 31, 2003, with those purchasers accounting for approximately 26% of revenues in the aggregate. For the year ended December 31, 2002, Eastex Crude Company and Contact Energy in New Zealand accounted for approximately 28% 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.

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 or barges 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 to Shell Petroleum Mining at international prices tied to the Asia Petroleum Price Index (APPI) Tapis posting, less the cost of storage, trucking, and transportation.

Our 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 that was modified in 2003 and covers approximately 7.2 Bcfe per year for a three year period. During 2003, additional production volumes from our TAWN fields, over the contract maximum, were sold to Contact Energy or Genesis Power Ltd. at prevailing market rates. The gas sales above the contract maximum expired at the end of 2003.

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

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and gas production for the three-year period ended December 31, 2003. "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,		
	2003	2002	2001
Net Sales Volume:			
Oil (Bbls) (1) (3)	4,192,612	3,770,128	3,055,373
Gas (Mcf)(2)	28,002,719	27,131,578	26,458,958
Gas equivalents (Mcfe)	53,158,384	49,752,346	44,791,202
Average Sales Price:			
Oil (Per Bbl) (1) (3)	\$ 27.47	\$ 20.88	\$ 22.64
Gas (Per Mcf) (2)	\$ 3.42	\$ 2.30	\$ 4.23
Average Production Cost (per Mcfe)	\$ 0.99	\$ 0.83	\$ 0.82

¹Oil production for 2003, 2002, and 2001 includes New Zealand production of 855,910 barrels at an average price per barrel of \$24.26, 695,454 barrels at an average price per barrel of \$20.28, and 84,261 barrels at an average price per barrel of \$21.64, respectively.

²Natural gas production for 2003 and 2002 includes New Zealand production of 14,258,679 Mcf with an average price of \$1.83 per Mcf, and 11,351,518 Mcf with an average price of \$1.32 per Mcf.

³In the table above, for 2003 and 2002, natural gas liquids have been combined with oil and condensate for reporting purposes. The natural gas liquids production for 2003 was 823,214 barrels at an average price of \$17.60 per barrel and 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, 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 six limited partnerships, we are solely responsible for the day-to-day conduct of those 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 if a significant accident, or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Our price-risk management 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.

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 subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to change and increase in both number and complexity. We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital costs of complying with the environmental regulations applicable to our operations is uncertain and will be governed by several factors, include future changes to regulatory requirements.

Both our domestic and our New Zealand operations are subject to 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. In addition, 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 U.S. federal government and are affected by the availability, terms and cost of transportation. In particular, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new rules and regulations affecting the natural gas industry. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex

rules and regulations issued by FERC cannot be predicted. Some of FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation.

Our domestic production of oil and gas is also 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 that may be 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 domestic properties are located on federal oil and gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and administrative orders affect the terms of leases, and in turn may affect our exploration and development plans, methods of operation, and related matters.

Employees

At December 31, 2003, we employed 241 persons. Of these employees, 58 were 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 \$164,000 per month. In New Zealand we lease approximately 16,000 square feet of office space, under leases expiring in 2009. These New Zealand leases require payments of approximately \$13,000 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 that we formed and for which we 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. Of the 109 partnerships, 21 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 2003, we continued to serve as managing general partner for six remaining partnerships, all of which are drilling partnerships that have been in existence from five to seven 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.

FASB — The Financial Accounting Standards Board.

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

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

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

MBbl — Thousand barrels of oil.

Mcf — Thousand cubic feet of natural gas.

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

MMBbl — Million barrels of oil.

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

MMcf — Million cubic feet of natural gas.

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

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

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

NGL— Natural gas liquid.

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.

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 2003 to a vote of security holders.

PART II

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

COMMON STOCK, 2002 AND 2003

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 2002 and 2003 were as follows:

	2002				2003			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	\$15.55	\$13.44	\$10.40	\$6.80	\$8.51	\$7.60	\$10.64	\$13.57
High	\$20.58	\$20.53	\$15.23	\$10.54	\$9.76	\$12.14	\$14.57	\$18.00

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 348 stockholders of record as of December 31, 2003.

Item 6. Selected Financial Data

	2003	2002	2001	2000	1999
Revenues					
Oil and Gas Sales	\$211,032,639	\$141,195,713	\$181,184,635	\$189,138,947	\$108,898,696
Fees from affiliated limited partnerships (1)	\$28,068	\$67,173	\$427,583	\$331,497	\$229,749
Interest Income	\$184,383	\$263,738	\$49,281	\$1,339,386	\$833,204
Other, Net	\$(2,344,107)	\$8,443,187	\$2,145,991	\$815,116	\$709,358
Total Revenues	\$208,900,983	\$149,969,811	\$183,807,490	\$191,624,946	\$110,671,007
Income (Loss) Before Income Taxes and Change in Accounting Principle (2)	\$50,739,178	\$18,408,289	(\$34,192,333)	92,449,488	\$29,736,151
Net Income (Loss)	\$29,893,812	\$11,923,227	(\$22,347,765)	\$59,184,008	\$19,286,574
Net Cash Provided by Operating Activities	\$110,827,279	\$71,626,314	\$139,884,255	\$128,197,227	\$73,603,426
Per Share Data					
Weighted Average Shares Outstanding(2)	27,357,579	26,382,906	24,732,099	21,244,684	18,050,106
Earnings (Loss) per Share--Basic(2)	\$1.09	\$0.45	(\$0.90)	\$2.79	\$1.07
Earnings (Loss) per Share--Diluted(2)	\$1.08	\$0.45	(\$0.90)	\$2.51	\$1.07
Shares Outstanding at Year-End	27,484,091	27,201,509	24,795,564	24,608,344	20,823,729
Book Value per Share	\$14.46	\$13.42	\$12.61	\$13.50	\$8.18
Market Price(2)					
High	\$18.00	\$20.58	\$37.70	\$43.50	\$13.31
Low	\$7.60	\$6.80	\$16.66	\$9.75	\$5.69
Year-End Close	\$16.85	\$9.67	\$20.20	\$37.63	\$11.50
<i>Pro forma amounts assuming 1994 change in Accounting principle is applied retroactively(1)</i>					
Net Income (Loss)	---	---	---	---	---
Earnings (Loss) per Share--Basic (2)	---	---	---	---	---
Earnings (Loss) per Share--Diluted (2)	---	---	---	---	---
Assets					
Current Assets	\$34,673,672	\$29,768,199	\$36,752,980	\$41,872,879	\$50,605,488
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization	\$816,459,776	\$721,617,941	\$628,304,060	\$524,052,828	\$392,986,589
Total Assets	\$861,054,932	\$767,005,859	\$671,684,833	\$572,387,001	\$454,299,414
Liabilities					
Current Liabilities	\$69,772,730	\$46,884,184	\$73,245,335	\$64,324,771	\$34,070,085
Long-Term Debt	\$340,254,783	\$324,271,973	\$258,197,128	\$134,729,485	\$239,068,423
Total Liabilities	\$463,663,668	\$401,932,675	\$359,032,113	\$240,232,846	\$283,895,297
Stockholders' Equity	\$397,391,264	\$365,073,184	\$312,652,720	\$332,154,155	\$170,404,117
Number of Employees	241	234	209	181	173
Producing Wells					
Swift Operated	870	820	854	817	769
Outside Operated	128	112	381	711	788
Total Producing Wells	998	932	1,235	1,528	1,557
Wells Drilled (Gross)	75	36	53	70	27
Proved Reserves					
Natural Gas (Mcf)	335,804,862	326,731,672	324,912,125	418,613,976	329,959,750
Oil, NGL, & Condensate (barrels)	80,759,903	70,438,963	53,482,636	35,133,596	20,806,263
Total Proved Reserves (Mcf equivalent)	820,364,284	749,365,449	645,807,939	629,415,552	454,797,327
Production (Mcf equivalent)(3)	53,158,384	49,752,346	44,791,202	42,356,705	42,874,303
Average Sales Price					
Natural Gas (per Mcf)	\$3.42	\$2.30	\$4.23	\$4.24	\$2.40
Oil (per barrel)	\$27.47	\$20.88	\$22.64	\$29.35	\$16.75

¹As of January 1, 1994, we changed our revenue recognition policy for earned interests. Accordingly, in 1994 to 2003, "Fees from affiliated limited partnerships" does not include earned interests revenues.

²Amounts have been retroactively restated in all periods presented to give recognition to: (a) an equivalent change in capital structure as a result of two 10% stock dividends, one in September 1994, the other in October 1997; (b) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share," and (c) the adoption in 2003 of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," which affected our presentation of 1999 results by reclassifying the loss on early extinguishment of debt from an extraordinary item to an operating item.

³Natural gas production for 1993, 1994, 1995, 1996, 1997, 1998, 1999, and 2000 includes 1,581,206; 1,358,375; 1,211,255; 1,156,361; 1,015,226; 866,232; 728,235; and 405,130 Mcf, respectively, delivered under our volumetric production payment agreement.

1998	1997	1996	1995	1994	1993
\$80,067,837	\$69,015,189	\$52,770,672	\$22,527,892	\$19,802,188	\$15,535,671
\$333,940	\$745,856	\$937,238	\$590,441	\$701,528	\$4,071,970
\$107,374	\$2,395,406	\$433,352	\$212,329	\$47,980	\$201,584
\$1,960,070	\$2,555,729	\$2,156,764	\$1,761,568	\$1,072,535	\$604,599
\$82,469,221	\$74,712,180	\$56,298,026	\$25,092,230	\$21,624,231	\$20,413,824
(\$73,391,581)	\$33,129,606	\$28,785,783	\$6,894,537	\$4,837,829	\$6,628,608
(\$48,225,204)	\$22,310,189	\$19,025,450	\$4,912,512	(\$13,047,027)	\$4,896,253
\$54,249,017	\$55,255,965	\$37,102,578	\$14,376,463	\$10,394,514	\$7,238,340
16,436,972	16,492,856	15,000,901	10,035,143	7,308,673	7,246,884
(\$2.93)	\$1.35	\$1.27	\$0.49	(\$1.79)	\$0.68
(\$2.93)	\$1.26	\$1.25	\$0.49	(\$1.79)	\$0.64
16,291,242	16,459,156	15,176,417	12,509,700	6,685,137	6,001,075
\$6.71	\$9.69	\$9.41	\$7.46	\$6.30	\$9.08
\$21.00	\$34.20	\$28.86	\$11.48	\$10.35	\$11.57
\$6.94	\$16.93	\$9.89	\$7.05	\$7.75	\$7.14
\$7.38	\$21.06	\$27.16	\$10.91	\$8.86	\$7.85
---	---	---	---	\$3,725,671	\$4,322,478
---	---	---	---	\$0.51	\$0.60
---	---	---	---	\$0.51	\$0.57
\$35,246,431	\$29,981,786	\$101,619,478	\$43,380,454	\$39,208,418	\$65,307,120
\$356,711,711	\$301,312,847	\$200,010,375	\$125,217,872	\$88,415,612	\$89,656,577
\$403,645,267	\$339,115,390	\$310,375,264	\$175,252,707	\$135,672,743	\$160,892,917
\$31,415,054	\$28,517,664	\$32,915,616	\$40,133,269	\$52,345,859	\$55,565,437
\$261,200,000	\$122,915,000	\$115,000,000	\$28,750,000	\$28,750,000	\$28,750,000
\$294,282,628	\$179,714,470	\$167,613,654	\$81,906,742	\$93,545,612	\$106,427,203
\$109,362,639	\$159,400,920	\$142,761,610	\$93,345,965	\$42,127,131	\$54,465,714
203	194	191	176	209	188
836	650	842	767	750	795
917	917	986	3,316	3,422	3,407
1,753	1,567	1,828	4,083	4,172	4,202
75	182	153	76	44	34
352,400,835	314,305,669	225,758,201	143,567,520	76,263,964	64,462,805
13,957,925	7,858,918	5,484,309	5,421,981	4,553,237	4,271,069
436,148,385	361,459,177	258,664,055	176,099,406	103,583,566	90,089,219
39,030,030	25,393,744	19,437,114	11,186,573	9,600,867	7,368,757
\$2.08	\$2.68	\$2.57	\$1.77	\$1.93	\$1.96
\$11.86	\$17.59	\$19.82	\$15.66	\$14.35	\$15.10

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis supplements and is provided to facilitate increased understanding of our 2003, 2002 and 2001 consolidated financial statements and our accompanying notes included with this report.

Overview

For 2003, Swift Energy experienced record revenues of \$209 million and record production of 53.2 Bcfe. Our revenues were bolstered by oil and gas prices remaining strong last year. Although 2003 domestic production decreased by 1% to 33.8 Bcfe from 2002 levels we continued to focus our efforts and capital throughout the year on better infrastructure, increased production and the development of longer life oil reserves in the Lake Washington area. In January 2004, we produced more than approximately 12,000 gross barrels of oil equivalent per day (approximately 10,000 net barrels of oil equivalent per day) in Lake Washington, compared to approximately 5,000 gross barrels of oil equivalent per day (approximately 4,100 net barrels of oil equivalent per day) in January 2003. During 2003, we also began allocating capital to natural gas development in our three other domestic core areas. New Zealand accounted for 19.4 Bcfe of 2003 production, a 25% increase from 2002 levels. New Zealand natural gas and NGL contracts are denominated in New Zealand Dollars, which have significantly strengthened during 2003 against the U.S. Dollar. The currency exchange rate increased from approximately \$0.52 to approximately \$0.66 U.S. per \$1.00 New Zealand during the year.

Our production costs were up in 2003 predominately due to some of the facility enhancement costs and increased activity and production in Lake Washington, increased severance taxes, and also due to currency exchange rates in New Zealand. Our average reserve replacement cost for 2003 was \$1.17 per Mcfe, and we replaced 234% of our 2003 production. Our general and administrative expenses increased in 2003 predominantly due to our increased activities in New Zealand, a reduction in reimbursement from partnerships we managed, an increase in franchise tax expense, and increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act. We are working to reduce our production costs for 2004.

We again made significant strides in 2003 in improving the quality and quantity of our reserve base in accordance with our strategic plan. Year-end 2003 proved reserves of 820.4 Bcfe, representing 9.5% growth for the year, were 47% crude oil, 41% natural gas and 12% NGLs, compared to year-end 2002 proved reserves of 749.4 Bcfe, which were 42% crude oil, 44% natural gas and 14% NGLs. Proved developed reserves remained essentially the same at 59% of total reserves at year-end 2003, compared to 60% the previous year. Domestic proved reserves increased at year-end 2003 to 644.4 Bcfe, driven mainly by the reserve increase in the Lake Washington Field. Proved reserves in New Zealand increased to 176.0 Bcfe at year-end 2003, primarily attributable to drilling additions in the Kauri and Manutahi Sands. For 2003, our proved undeveloped reserves, 41% of total reserves, were slightly higher than the 30% to 40% range we had targeted. Most of these proved undeveloped reserves were in the Lake Washington area (13% of total reserves) and in the AWP Olmos area (9% of total reserves), and both areas are characterized as long reserve life fields. The 30% to 40% range is again our target for 2004 as we work to convert proved undeveloped reserves into proved producing reserves.

Our debt to PV-10 ratio has decreased from 43% in 2001 to 28% in 2002, and further decreased to 22% for 2003. Our debt to capitalization ratio was 46% at December 31, 2003, which is essentially the same as at year-end 2002, and 2001. Management continues to believe that our current cash flow is best utilized on capital projects rather than reducing debt. However, we will continue to look for opportunities in 2004 to improve our balance sheet and liquidity but expect our capital expenditures to continue to equal or modestly exceed our cash flow for the near term.

Our 2004 capital expenditure budget assumes increased drilling activity in all domestic core areas except Lake Washington. For Lake Washington, the 2004 budget assumes reduced drilling activity, 25 to 30 wells, accompanied by an extensive three-dimensional seismic survey, together with the analysis of the resulting data, to enhance our drilling program in the area for years to come. We plan to drill 15 to 18 wells in AWP Olmos, with the objective of again maintaining production levels in that area. Additionally, we expect to have ongoing exploratory efforts in our South Texas Garcia Ranch properties. In New Zealand, we plan to drill 8 to 12 wells, primarily in the areas in which we had success in 2003. We continue to see a tightening natural gas market with strengthening

gas prices in New Zealand. For 2004, we believe we are positioned for production growth of 11% to 17% and reserve growth of 5% to 8%, and expect commodity prices to remain strong.

Results of Operations

Revenues. Our revenues in 2003 increased by 39% compared to revenues in 2002, due primarily to increases in oil and gas prices and production from our New Zealand and Lake Washington areas. Revenues in 2002 decreased by 18% compared to 2001 revenues primarily due to the drop in domestic natural gas prices in 2002. Revenues from our oil and gas sales comprised substantially all of net revenues for 2003, 94% of total revenues for 2002, and 99% for 2001. Natural gas production made up 53% of our production volumes in 2003, 55% in 2002, and 59% in 2001. Domestic natural gas production made up 49% of our total natural gas production volumes in 2003, 58% in 2002, and 100% in 2001.

Oil and gas sales in 2003 increased by 49%, or \$69.8 million, from the level of those revenues for 2002, and our net sales volumes in 2003 increased by 7%, or 3.4 Bcfe, over net sales volumes in 2002. Average prices received for oil increased to \$29.89 per Bbl in 2003 from \$24.52 per Bbl in 2002. Average gas prices received increased to \$3.42 per Mcf in 2003 from \$2.30 per Mcf in 2002. Average NGL prices received increased to \$17.60 per Bbl in 2003 from \$12.82 per Bbl in 2002. The increase in production during the 2003 period was primarily from our New Zealand and Lake Washington areas.

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

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

In 2002, oil and gas sales decreased by 22%, or \$40.0 million, from the level of those revenues in 2001 even though our net sales volumes in 2002 increased by 11%, or 5.0 Bcfe, over net sales volumes in 2001. Average combined prices received for oil and NGLs 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 was primarily from our New Zealand and Lake Washington areas.

In 2002, our \$40.0 million decrease in oil, NGL, 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 combined oil and NGL 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 and NGL sales volumes, and \$2.8 million of the increases from the 0.7 Bcf increase in gas sales volumes.

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

Area	Oil and Gas Sales (In millions)		Net Oil and Gas Sales Volume (Bcfe)	
	2003	2002	2003	2002
AWP Olmos	\$ 43.7	\$ 33.1	8.4	10.9
Brookeland	16.4	11.9	3.9	4.1
Lake Washington	59.5	18.5	12.1	4.4
Masters Creek	25.7	32.3	5.7	9.7
Other	18.9	16.3	3.7	5.2
Total Domestic	\$164.2	\$112.1	33.8	34.3
Rimu/Kauri	11.6	4.0	3.3	1.5
TAWN	35.2	25.1	16.1	14.0
Total New Zealand	\$ 46.8	\$ 29.1	19.4	15.5
Total	\$211.0	\$141.2	53.2	49.8

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

	Net Oil and Gas Sales Volume			Average Sales Price	
	Oil and NGLs (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil and NGLs (Bbl)	Gas (Mcf)
2001:					
First	603	6.7	10.3	\$27.63	\$6.86
Second	691	7.1	11.3	\$26.05	\$4.66
Third	813	6.8	11.7	\$23.76	\$2.94
Fourth	948	5.9	11.5	\$16.02	\$2.21
	<u>3,055</u>	<u>26.5</u>	<u>44.8</u>	\$22.64	\$4.23
2002:					
First	944	6.6	12.3	\$16.10	\$1.72
Second	1,002	6.7	12.7	\$20.98	\$2.60
Third	908	6.7	12.2	\$23.05	\$2.32
Fourth	916	7.1	12.6	\$23.55	\$2.55
	<u>3,770</u>	<u>27.1</u>	<u>49.8</u>	\$20.88	\$2.30
2003:					
First	864	7.6	12.9	\$30.55	\$3.71
Second	1,033	7.1	13.3	\$25.48	\$3.47
Third	1,164	6.7	13.6	\$26.60	\$3.17
Fourth	1,132	6.6	13.4	\$27.84	\$3.29
	<u>4,193</u>	<u>28.0</u>	<u>53.2</u>	\$27.47	\$3.42

In the table above, for 2002 and 2003, natural gas liquids have been combined with oil for reporting purposes. Natural gas liquids production for 2002 was 1,174 MBbls, at an average price of \$12.82 per barrel; and for 2003, was 823 MBbls, at an average price of \$17.60 per barrel.

Costs and Expenses. Our expenses in 2003 increased \$26.6 million, or 20%, compared to 2002 expenses. The majority of the increase was due to the \$11.4 million increase in oil and gas production costs and the \$6.8 million increase in depreciation, depletion and amortization, both of which increased as our production volumes increased in 2003. Our expenses in 2002 decreased by \$86.4 million, or 40%, compared to 2001 expenses. This decrease was due primarily to the \$98.9 million non-cash write-down of domestic oil and gas properties in 2001.

As discussed in Note 1 to the Consolidated Financial Statements, we adopted SFAS No. 143 on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of \$4.4 million, which is recorded as a "Cumulative Effect of Change in Accounting Principle" in the 2003 consolidated statement of income. 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 \$0.4 million, which is recorded as a "Cumulative Effect of Change in Accounting Principle" in the 2001 consolidated statement of income.

Our 2003 general and administrative expenses, net increased \$3.5 million, or 33%, from the level of such expenses in 2002, while 2002 general and administrative expenses increased \$2.4 million, or 29%, over 2001 levels. These increases in 2002 and 2003 are due primarily to our increased activities in New Zealand and a reduction in reimbursement from partnerships we managed as almost all of these partnerships have liquidated. In addition, our 2003 expense increased due to an increase in franchise tax expense and increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act. Our general and administrative expenses per Mcfe produced increased to \$0.27 per Mcfe in 2003 from \$0.21 per Mcfe in 2002 and \$0.18 per Mcfe in 2001. The portion of supervision fees recorded as a reduction to general and administrative expenses was \$3.6 million for 2003, \$3.2 million for 2002, and \$3.5 million for 2001.

Depreciation, depletion, and amortization of our oil and gas properties, or DD&A, increased \$6.8 million, or 12%, in 2003 from 2002 levels, while 2002 DD&A decreased \$3.3 million, or 6%, from 2001 levels. Domestically, DD&A increased \$1.0 million in 2003 due to increases in the depletable oil and gas property base, offset by slightly lower production in the 2003 period and higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, DD&A increased by \$5.8 million in 2003 due to increased production in the 2003 period. In 2002, our domestic DD&A decreased by \$15.6 million due to lower production in the 2002 period and the domestic non-cash write-down of oil and gas properties in the fourth quarter of 2001 that decreased our depletable base, along with higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, our 2002 DD&A increased \$12.3 million as our production and the depletable oil and gas property base both increased in the 2002 period due primarily to the TAWN acquisition. Our DD&A rate per Mcfe of production was \$1.19 in 2003, \$1.13 in 2002, and \$1.33 in 2001, reflecting variations in per unit cost of reserves additions.

We recorded \$0.9 million of accretion on our asset retirement obligation in 2003 associated with the adoption of SFAS No. 143 implemented on January 1, 2003.

Our production costs per Mcfe produced were \$0.99 in 2003, \$0.83 in 2002, and \$0.82 in 2001. The portion of supervision fees recorded as a reduction to production costs was \$1.5 million for 2003, \$2.1 million for 2002, and \$3.3 million for 2001. Our production costs in 2003 increased \$11.4 million, or 27%, over such expenses in 2002, while those expenses in 2002 increased \$4.8 million, or 13%, over such expenses in 2001. Approximately \$6.2 million of the increase in production costs during 2003 was related to domestic severance taxes, which increased along with commodity prices and higher production from our Lake Washington area in that period. In New Zealand, production costs increased by \$5.2 million in 2003 mainly due to royalty payments made on higher production in the period. In 2002 production costs increased as our New Zealand activities increased, partially offsetting the domestic production costs decrease, which mainly was due to a decrease in production volumes.

Interest expense on our Senior Notes issued in April 2002, including amortization of debt issuance costs, totaled \$19.1 million in 2003 and \$13.5 million in 2002. Interest expense on our Senior Notes issued in July 1999, including amortization of debt issuance costs, totaled \$13.2 million in both 2003 and 2002 and \$13.1 million in 2001. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled \$1.6 million in 2003, \$3.6 million in 2002, and \$5.8 million in 2001. Other interest cost was \$0.3 million in 2003. The total interest cost in 2003 was \$34.2 million, of which \$6.9 million was capitalized. The total interest cost in 2002 was \$30.3 million, of which \$7.0 million was capitalized. The 2001 total interest cost was \$18.9 million, of which \$6.3 million was capitalized. We capitalize that portion of interest related to unproved properties. The increase in interest expense in 2003 and 2002 was attributed to the replacement of our bank borrowings in April 2002 with the Senior Notes issued in 2002 that carry a higher interest rate.

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.

Income tax expense in 2003 includes a reduction of approximately \$1.3 million from the U.S. statutory rate, primarily from the result of the currency exchange rate effect on the New Zealand deferred tax. This amount is partially offset by higher deferred state taxes and other items.

Net Income (Loss). Our net income in 2003 of \$29.9 million was 151% higher and basic earnings per share ("Basic EPS") of \$1.09 were 142% higher than our 2002 net income of \$11.9 million and Basic EPS of \$0.45. Our earnings per diluted share ("Diluted EPS") in 2003 of \$1.08 were 140% higher than our 2002 Diluted EPS of \$0.45. These amounts increased in the 2003 period as oil and gas sales increased due to higher commodity prices and increased production.

Our net income in 2002 of \$11.9 million was 153% higher and Basic EPS of \$0.45 was 150% higher than our 2001 net loss of \$(22.3) million and Basic EPS of \$(0.90). Our Diluted EPS in 2002 of \$0.45 was 150% higher than our 2001 Diluted EPS 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 in 2002, offset somewhat by lower revenue in 2002 due to lower commodity prices.

Proved Oil and Gas Reserves. At year-end 2003, our total proved reserves were 820.4 Bcfe with a PV-10 Value of \$1.5 billion. In 2003, our proved natural gas reserves increased 9.1 Bcf, or 3%, while our proved oil reserves increased 10.3 MMBbl, or 15%, for a total equivalent increase of 71.0 Bcfe, or 9%. In 2002, our proved natural gas reserves increased by 1.8 Bcf, or 1%, while our proved oil reserves increased by 17.0 MMBbl, or 32%, for a total equivalent increase of 103.6 Bcfe, or 16%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 105.6 Bcfe (36.1 Bcfe of which came from New Zealand) of proved reserves in 2003, 83.9 Bcfe (15.9 Bcfe of which came from New Zealand) in 2002, and 105.8 Bcfe (17.4 Bcfe of which came from New Zealand) in 2001. Through acquisitions we added 0.5 Bcfe of proved reserves in 2003, 74.2 Bcfe in 2002, and 54.6 Bcfe in 2001. At year-end 2003, 59% of our total proved reserves were proved developed, compared with 60% at year-end 2002 and 50% at year-end 2001.

The PV-10 Value of our total proved reserves increased 33% from the PV-10 Value at year-end 2002. Gas prices increased in 2003 to \$4.56 per Mcf from \$3.49 per Mcf at year-end 2002, compared to \$2.51 per Mcf at year-end 2001. Oil prices increased in 2003 to \$30.16 per barrel from \$29.27 per Bbl at year-end 2002, compared to \$18.45 in 2001. 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 as of December 31, 2003 are as follows:

	2004	2005	2006	2007	2008	Thereafter	Total
Non-cancelable operating lease commitments	\$2,143,447	\$492,613	\$159,065	\$156,649	\$125,132	\$13,500	\$3,090,406
Capital commitments due to pipeline operators	96,244	---	---	---	---	---	96,244
Asset Retirement Obligation (1)	1,703,549	2,603,866	---	129,478	74,286	5,626,294	10,137,473
Drilling Rig and Seismic Commitments	5,919,000	---	---	---	---	---	5,919,000
Senior Notes due 2009 (2)	---	---	---	---	---	125,000,000	125,000,000
Senior Notes due 2012 (2)	---	---	---	---	---	200,000,000	200,000,000
Credit Facility which expires in October 2005 (3)	---	15,900,000	---	---	---	---	15,900,000
	<u>\$9,862,240</u>	<u>\$18,996,479</u>	<u>\$159,065</u>	<u>\$286,127</u>	<u>\$199,418</u>	<u>\$330,639,794</u>	<u>\$360,143,123</u>

¹Amounts shown by year are the fair values at December 31, 2003.

²These amounts do not include the interest obligation, which is paid semiannually.

³These amounts exclude a \$0.8 million standby letter of credit outstanding under this facility.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. Worldwide supply disruptions, such as the reduction in crude oil production from Venezuela, together with perceived risks associated with the unrest in Iraq, along with other factors, have caused the price of oil to increase significantly in 2003 when compared to historical prices. Other factors such as actions taken by OPEC, worldwide economic conditions, weather conditions, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices increased significantly in the first quarter of 2003 when compared to historical prices and have since declined somewhat. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas. Such factors are beyond our control.

Liquidity and Capital Resources

During 2003, we largely relied upon cash provided by operating activities of \$110.8 million, proceeds from bank borrowings of \$15.9 million, and proceeds from the sale of property and equipment of \$10.2 million to fund capital expenditures of \$144.5 million. During 2002, we principally relied upon cash provided by operating activities of \$71.6 million, net proceeds from the issuance of long-term debt of \$195.0 million, 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. For 2004, we believe that our credit facility and cash flow will be sufficient to fund our planned capital expenditures.

Net Cash Provided by Operating Activities. In 2003, net cash provided by our operating activities increased by 55% to \$110.8 million, as compared to \$71.6 million in 2002 and \$139.9 million in 2001. The 2003 increase of \$39.2 million was primarily due to an increase of oil and gas sales of \$69.8 million due to higher commodity prices and production. 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 higher debt balances and interest rates in 2002.

Existing Credit Facilities. At December 31, 2003, we had \$15.9 million in outstanding borrowings under our credit facility. At December 31, 2002, we had no outstanding borrowings under this facility. Our credit facility at

year-end 2003 consisted of a \$300.0 million revolving line of credit with a \$250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group and increased to \$250.0 million, effective November 1, 2003. We requested that the commitment amount with our bank group be reduced to \$150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. 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.

Our \$125.0 million Senior Notes mature on August 1, 2009 and are callable August 1, 2004. Our \$200.0 million Senior Notes mature on May 1, 2012. The indentures underlying our Senior Notes contain covenants that impose restrictions on us. Under the indentures, we are limited to the amount of debt that we can incur such that in general, after giving pro forma effect to such new debt, the consolidated interest coverage ratio would not exceed 2.5 to 1.0, or our indebtedness under our bank credit facility does not exceed the greater of \$250.0 million or \$150.0 million plus 25% of adjusted consolidated net tangible assets as defined under the indentures. The aggregate amount of our common stock that we can repurchase is limited to \$5.0 million under the indenture governing our Senior Notes due 2012 and \$2.0 million under the indenture governing our Senior Notes due 2009. We believe that these restrictions will not have any material effect upon our business for the foreseeable future.

In January 2004, we filed a universal shelf registration statement with the SEC to allow us to offer up to \$350 million of our securities in the future. Upon effectiveness of the registration statement, for a period of two years we may periodically offer one or more of these securities in amounts, prices and on terms to be announced when and if the securities are offered. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Working Capital. Our working capital declined from a negative \$17.1 million at December 31, 2002, to a negative \$35.1 million at December 31, 2003. The decrease was primarily due to an increase in accounts payable and accrued liabilities due to our year-end 2003 drilling activities. Consistent with prior years, we can draw on our available credit facility to remedy our working capital deficit if needed.

Capital Expenditures. In 2003, our capital expenditures of approximately \$144.5 million included:

Domestic activities of \$114.4 million, or 79% of total expenditures, as follows:

- \$57.0 million, or 39%, on developmental drilling, primarily in our Lake Washington area;
- \$25.9 million, or 18%, for the construction of production and surface facilities, mainly in our Lake Washington area;
- \$11.9 million, or 8%, on exploratory drilling, primarily in our Lake Washington area;
- \$11.4 million, or 8%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- \$4.4 million, or 3%, on field compression facilities;
- \$2.0 million, or 1%, for producing property acquisitions, including the purchase of property interests from partnerships managed by us;
- \$0.9 million, or less than 1%, for fixed assets; and
- \$0.9 million, or less than 1%, on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand activities of \$30.1 million, or 21% of total expenditures, as follows:

- \$15.1 million, or 10%, on developmental activities primarily to further delineate the Rimu and Kauri areas;
- \$6.4 million, or 4%, on prospect costs;
- \$5.7 million, or 4%, on gas processing plants;
- \$2.3 million, or 2%, for exploratory drilling mainly for the Tuihu exploratory well;
- \$0.3 million, or less than 1%, on producing properties acquisitions; and
- \$0.3 million, or less than 1%, for fixed assets.

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

We currently plan to spend \$130 to \$150 million in total capital expenditures in 2004, excluding acquisition costs and net of approximately \$5 million to \$15 million in non-core property dispositions. The budget for 2004, as always, is dependent upon operational performance and commodity pricing levels during the year. Domestic activities account for 80% of budgeted spending, with the largest allocation going to the Lake Washington area.

We believe that the anticipated internally generated cash flows for 2004, together with bank borrowings under our credit facility, will be sufficient to finance the costs associated with our currently budgeted 2004 capital expenditures. If producing property acquisitions become attractive during 2004, we will explore the use of debt and/or equity offerings to fund such activity.

Our capital expenditures were approximately \$155.2 million in 2002 and \$275.1 million in 2001. 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. 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. Our capital expenditures in 2002 included:

New Zealand activities of \$95.2 million, or 61% of total expenditures, as follows:

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

Domestic activities of \$60.0 million, or 39% of total expenditures, as follows:

- \$34.4 million, or 22%, on developmental drilling;
- \$11.1 million, or 7%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- \$8.3 million, or 5%, on exploratory drilling;
- \$2.3 million, or 1%, for producing property acquisitions, including the purchase of property interests from partnerships managed by us;
- \$2.0 million, or 1%, on gas processing plants in the Brookeland and Masters Creek areas;
- \$1.1 million, or less than 1%, on field compression facilities; and
- \$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 completed. In New Zealand we drilled three development wells and three exploratory wells. One of the development wells and one of the exploratory wells were unsuccessful.

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. Significant estimates include proved reserve volumes, DD&A, and deferred income taxes.

Property and Equipment. We follow the “full-cost” method of accounting for oil and gas property and equipment costs as described in detail in Note 1 to our Consolidated Financial Statements. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. For the years 2003, 2002, and 2001, internal costs capitalized totaled \$11.5 million, \$10.7 million, and \$11.6 million, respectively. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. For the years 2003, 2002, and 2001, capitalized interest on unproved properties totaled \$6.8 million, \$7.0 million, and \$6.3 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

Full-Cost Ceiling Test. These capitalized costs are subject to a ceiling test, however, which limits the unamortized cost of oil and gas properties, including deferred income taxes, to the sum of the estimated future net revenues from proved properties, excluding cash outflows from asset retirement obligations, using hedge adjusted 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”). Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end price and thus did not affect prices used in this calculation.

At December 31, 2003 and 2002, our unamortized costs of natural gas and oil properties did not exceed the ceiling amount. At December 31, 2003, our PV-10 value was calculated based upon quoted market prices of \$4.56 per Mcf for gas and \$30.16 per barrel for oil, adjusted for market differentials. 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. A decline in natural gas and oil prices from year-end 2003 levels or other factors, without mitigating circumstances, could cause a future non-cash write-down of capitalized costs and a non-cash charge against future earnings.

Accounts Receivable. Included in the total “Accounts receivable” balance, which totaled \$28.6 million and \$20.9 million at December 31, 2003 and 2002, respectively, on the accompanying balance sheet, was approximately \$2.3 million of receivables related to volumes produced from 2001 and 2002 that we were notified were disputed in early 2003. Accordingly, we did not record a receivable to date with regard to 2003 volumes. We assess the collectibility of trade and other receivables. Based on our judgment, we would accrue a reserve when we believe a receivable may not be collected. At December 31, 2003 and 2002, we had an allowance for doubtful accounts of \$0.8 million and \$0.3 million, respectively. These allowance for doubtful accounts balances have been deducted from the total “Accounts receivable” balances on the balance sheet included in our Consolidated Financial Statements.

Price-Risk Management Activities. We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. We adopted SFAS No. 133 effective January 1, 2001, which requires that changes in the derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met as further described in Note 1 to our Consolidated Financial Statements.

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 \$0.4 million, which was recorded as a Cumulative Effect of Change in Accounting Principle. During 2003, 2002 and 2001, we recognized net losses (gains) of \$2.8 million, \$0.2 million and (\$1.2 million), respectively, relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. At December 31, 2003, we had recorded \$0.3 million, net of taxes of \$0.2 million, 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 transactions that qualified as cash flow hedges. The ineffectiveness reported in “Price-risk management and other, net” for 2003 and 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 when the forecasted sale of hedge products occurs.

As of December 31, 2003, we had in place natural gas price floors in effect for the January 2004 contract month through the June 2004 contract month that cover our domestic natural gas production for January 2004 to June 2004. The natural gas price floors cover notional volumes of 3,300,000 Mmbtu with a weighted average floor price of \$4.77. When we entered into these transactions they were designated as a hedge of the variability in cash flows associated with the forecasted sale of 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 reclassified 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 at December 31, 2003, was \$0.5 million and is recognized on the balance sheet in "Other current assets."

In January 2004, we entered into additional natural gas "floors" covering contract periods April 2004 to June 2004, which cover our natural gas production for January 2004 to June 2004. Notional volumes are 200,000 MMBtu per month at a weighted average floor price of \$5.00 per MMBtu.

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

Stock Based Compensation. We have three stock-based compensation plans, which are described more fully in Note 6 to our Consolidated Financial Statements. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. 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; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant.

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

New Accounting Pronouncements. In June 2002, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142 "Goodwill and Intangible Assets." We adopted these statements on July 1, 2001, and January 1, 2002, respectively. An issue has arisen for companies engaged in oil and gas exploration and production regarding the application of SFAS No. 141 and SFAS No. 142 as they relate to mineral rights held under lease or other contractual arrangements and as to whether costs associated with these rights should be classified as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs. We understand that the Emerging Issues Task Force of the FASB has placed this issue on its agenda, although the date and the outcome of the resolution of the issue is unknown.

Historically we have classified our oil and gas mineral rights held under lease as tangible assets along with our other oil and gas properties, which is in accordance with the Securities and Exchange Commission's ("SEC") full cost accounting rules, and we intend to continue to do so until further guidance is provided. We have estimated the amount associated with these mineral rights using historical depletion rates, estimates of the timing of impairment of unproved properties and assuming the cost for the mineral rights was unaffected by the ceiling test write-down recorded in December 2001 because we cannot associate the ceiling test write-down with particular types of costs. Based on these limitations and assumptions, we estimate the net cost of mineral rights that would be reclassified from oil and gas properties to intangible assets to be approximately \$55-60 million at December 31, 2003 and approximately \$45-50 million at December 31, 2002. These

amounts are from July 1, 2001 (the date we adopted SFAS No. 141) to December 31, 2003 as we are not able to calculate amounts to reclassify before that period as our property records did not break out that information. Only our balance sheet accounts would be affected by the reclassification, and our results of operations and cash flows would not be materially impacted by any such reclassification.

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 2003, 2002, and 2001 totaled approximately \$0.2 million, \$0.3 million, and \$0.9 million, 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 \$0.4 million, \$1.0 million, and \$3.1 million in 2003, 2002, and 2001, 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 \$0.1 million, \$0.5 million, and \$2.4 million in 2003, 2002, and 2001, respectively.

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 expected to continue.

Our price-risk management policy 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 March 1, 2004, we had in place price floors in effect through the June 2004 contract month for natural gas, these cover our domestic natural gas production for March 2004 to June 2004. The natural gas price floors cover notional volumes of 2,550,000 MMBtu, with a weighted average floor price of \$4.84 per MMBtu. Our hedges in place at March 1, 2004 are expected to cover approximately 55% to 65% of our domestic natural gas production from March 2004 to June 2004.
- *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, 2003, we had \$15.9 million in outstanding borrowings under our credit facility, which bears a floating rate of interest and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 40 basis points and would reduce 2004 cash flows by \$0.1 million based on the December 31, 2003 level of borrowing.

Income Tax Carryforwards. We have significant federal and state net operating loss and capital loss carryforwards at December 31, 2003. The Company has not recorded a valuation allowance against the deferred tax assets attributable to these carryovers at December 31, 2003, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts. If we are not able to use our carryforwards, our results of operations and cash flows will be negatively impacted.

Financial Instruments and Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2003 and 2002, 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 \$135.6 million at December 31, 2003, and \$129.0 million at December 31, 2002. Based upon quoted market prices as of the respective dates, the fair value of our Senior Notes due 2012 was \$218.0 million at December 31, 2003, and \$189.2 million at December 31, 2002. Our credit facility with the banks expires October 1, 2005.

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

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers, who are mainly in the energy industry. Our ability to collect on sales to our customers is dependent on the liquidity of our

customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe the loss of any single oil or gas customer would materially affect our revenues.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Auditors

Board of Directors
Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2003. 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. The consolidated financial statements of Swift Energy Company and subsidiaries for the year 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 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 2002 and 2003 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States.

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

ERNST & YOUNG LLP

Houston, Texas
February 10, 2004

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.

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

	December 31,	
	2003	2002
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 1,066,280	\$ 3,816,107
Accounts receivable-		
Oil and gas sales	26,942,920	17,360,716
Affiliated limited partnerships	356,118	191,964
Joint interest owners	1,350,707	3,364,846
Other current assets	4,957,647	5,034,566
Total Current Assets	<u>34,673,672</u>	<u>29,768,199</u>
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,305,763,355	1,150,633,802
Unproved properties	67,557,969	69,603,481
	<u>1,373,321,324</u>	<u>1,220,237,283</u>
Furniture, fixtures, and other equipment	10,602,786	9,595,944
	<u>1,383,924,110</u>	<u>1,229,833,227</u>
Less – Accumulated depreciation, depletion, and amortization	(567,464,334)	(504,323,773)
	<u>816,459,776</u>	<u>725,509,454</u>
Other Assets:		
Deferred income taxes	1,905,909	2,680,585
Debt issuance costs	8,015,575	9,047,621
	<u>9,921,484</u>	<u>11,728,206</u>
	<u>\$ 861,054,932</u>	<u>\$ 767,005,859</u>
 LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 63,100,669	\$ 43,028,708
Payable to affiliated limited partnerships	516,006	91,126
Undistributed oil and gas revenues	6,156,055	3,764,350
Total Current Liabilities	<u>69,772,730</u>	<u>46,884,184</u>
Long-Term Debt	340,254,783	324,271,973
Deferred Income Taxes	43,498,682	30,776,518
Asset Retirement Obligation	10,137,473	---
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, \$.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, \$.01 par value, 85,000,000 shares authorized, 28,011,109 and 27,811,632 shares issued, and 27,484,091 and 27,201,509 shares outstanding, respectively	280,111	278,116
Additional paid-in capital	334,865,204	333,543,471
Treasury stock held, at cost, 527,018 and 610,123 shares, respectively	(7,558,093)	(8,749,922)
Retained earnings	70,073,384	40,179,572
Accumulated other comprehensive loss, net of income tax	(269,342)	(178,053)
	<u>397,391,264</u>	<u>365,073,184</u>
	<u>\$ 861,054,932</u>	<u>\$ 767,005,859</u>

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries

	Year Ended December 31,		
	2003	2002	2001
Revenues:			
Oil and gas sales	\$ 211,032,639	\$ 141,195,713	\$ 181,184,635
Fees from affiliated limited partnerships	28,068	67,173	427,583
Interest income	184,383	263,738	49,281
Gain on asset disposition	---	7,332,668	---
Price-risk management and other, net	(2,344,107)	1,110,519	2,145,991
	<u>208,900,983</u>	<u>149,969,811</u>	<u>183,807,490</u>
Costs and Expenses:			
General and administrative, net	14,097,066	10,564,849	8,186,654
Depreciation, depletion, and amortization	63,072,057	56,224,392	59,502,040
Accretion of asset retirement obligation	857,356	---	---
Oil and gas production	52,866,802	41,497,312	36,719,609
Interest expense, net	27,268,524	23,274,969	12,627,022
Other expenses	---	---	2,102,251
Write-down of oil and gas properties	---	---	98,862,247
	<u>158,161,805</u>	<u>131,561,522</u>	<u>217,999,823</u>
Income (Loss) Before Income Taxes and Change in Accounting Principle	50,739,178	18,408,289	(34,192,333)
Provision (Benefit) for Income Taxes	16,468,514	6,485,062	(12,237,436)
Income (Loss) Before Change In Accounting Principle	\$ 34,270,664	\$ 11,923,227	\$ (21,954,897)
Cumulative Effect of Change in Accounting Principle (net of taxes)	4,376,852	---	392,868
Net Income (Loss)	<u>\$ 29,893,812</u>	<u>\$ 11,923,227</u>	<u>\$ (22,347,765)</u>
Per Share Amounts-			
Basic: Income (Loss) Before Change in Accounting Principle	\$ 1.25	\$ 0.45	\$ (0.89)
Change in Accounting Principle	(0.16)	---	(0.01)
Net Income (Loss)	<u>\$ 1.09</u>	<u>\$ 0.45</u>	<u>\$ (0.90)</u>
Diluted: Income (Loss) Before Change in Accounting Principle	\$ 1.24	\$ 0.45	\$ (0.89)
Change in Accounting Principle	(0.16)	---	(0.01)
Net Income (Loss)	<u>\$ 1.08</u>	<u>\$ 0.45</u>	<u>\$ (0.90)</u>
Weighted Average Shares Outstanding	<u>27,357,579</u>	<u>26,382,906</u>	<u>24,732,099</u>

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)	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2000	\$ 254,521	\$ 293,396,723	\$ (12,101,199)	\$ 50,604,110	\$ -	\$ 332,154,155
Stock issued for benefit plans (11,945 shares)	72	354,973	68,408	-	-	423,453
Stock options exercised (152,915 shares)	1,529	1,942,634	-	-	-	1,944,163
Employee stock purchase plan (22,360 shares)	224	478,490	-	-	-	478,714
Comprehensive income:						
Net loss	-	-	-	(22,347,765)	-	(22,347,765)
Total comprehensive income	-	-	-	-	-	(22,347,765)
Balance, December 31, 2001	<u>\$ 256,346</u>	<u>\$ 296,172,820</u>	<u>\$ (12,032,791)</u>	<u>\$ 28,256,345</u>	<u>\$ -</u>	<u>\$ 312,652,720</u>
Stock issued for benefit plans (38,149 shares)	292	617,960	127,795	-	-	746,047
Stock options exercised (112,995 shares)	1,130	1,206,413	-	-	-	1,207,543
Public stock offering (1,725,000 shares)	17,250	30,465,809	-	-	-	30,483,059
Employee stock purchase plan (9,801 shares)	98	122,343	-	-	-	122,441
Stock issued in acquisitions (520,000 shares)	3,000	4,958,126	3,155,074	-	-	8,116,200
Comprehensive income:						
Net income	-	-	-	11,923,227	-	11,923,227
Change in fair value of cash flow hedges, net of income tax	-	-	-	-	(178,053)	(178,053)
Total comprehensive income	-	-	-	-	-	11,745,174
Balance, December 31, 2002	<u>\$ 278,116</u>	<u>\$ 333,543,471</u>	<u>\$ (8,749,922)</u>	<u>\$ 40,179,572</u>	<u>\$ (178,053)</u>	<u>\$ 365,073,184</u>
Stock issued for benefit plans (83,201 shares)	1	(408,178)	1,191,829	-	-	783,652
Stock options exercised (142,807 shares)	1,428	1,315,964	-	-	-	1,317,392
Employee stock purchase plan (56,574 shares)	566	413,947	-	-	-	414,513
Comprehensive income:						
Net income	-	-	-	29,893,812	-	29,893,812
Change in fair value of cash flow hedges, net of income tax	-	-	-	-	(91,289)	(91,289)
Total comprehensive income	-	-	-	-	-	29,802,523
Balance, December 31, 2003	<u>\$ 280,111</u>	<u>\$ 334,865,204</u>	<u>\$ (7,558,093)</u>	<u>\$ 70,073,384</u>	<u>\$ (269,342)</u>	<u>\$ 397,391,264</u>

(1)\$0.01 par value.

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Swift Energy Company and Subsidiaries

	Year Ended December 31,		
	2003	2002	2001
Cash Flows from Operating Activities:			
Net income (loss)	\$ 29,893,812	\$ 11,923,227	\$ (22,347,765)
Adjustments to reconcile net income (loss) to net cash provided by operating activities-			
Cumulative effect of change in accounting principle	4,376,852	---	---
Depreciation, depletion, and amortization	63,072,057	56,224,392	59,502,040
Write-down of oil and gas properties	---	---	98,862,247
Accretion of asset retirement obligation	857,356	---	---
Deferred income taxes	16,332,492	6,482,724	(12,555,618)
Gain on asset disposition	---	(7,332,668)	---
Other	908,927	270,770	509,973
Change in assets and liabilities-			
(Increase) decrease in accounts receivable, excluding income taxes receivable	(7,163,304)	283,419	16,207,377
Increase in accounts payable and accrued liabilities	2,542,803	3,174,450	12,984
(Increase) decrease in income taxes receivable and payable	6,284	600,000	(306,983)
Net Cash Provided by Operating Activities	<u>110,827,279</u>	<u>71,626,314</u>	<u>139,884,255</u>
Cash Flows from Investing Activities:			
Additions to property and equipment	(144,503,180)	(155,233,923)	(275,126,333)
Proceeds from the sale of property and equipment	10,186,970	13,256,674	9,274,440
Net cash received as operator of oil and gas properties	3,073,718	4,152,645	5,927,539
Net cash received (distributed) as operator of partnerships	260,726	(23,241,501)	(3,574,601)
Other	(71,193)	(39,953)	(534,898)
Net Cash Used in Investing Activities	<u>(131,052,959)</u>	<u>(161,106,058)</u>	<u>(264,033,853)</u>
Cash Flows from Financing Activities:			
Proceeds from long-term debt	---	200,000,000	---
Net proceeds from (payments of) bank borrowings	15,900,000	(134,000,000)	123,400,000
Net proceeds from issuances of common stock	1,575,853	31,409,200	1,633,508
Payments of debt issuance costs	---	(6,262,435)	(721,756)
Net Cash Provided by Financing Activities	<u>17,475,853</u>	<u>91,146,765</u>	<u>124,311,752</u>
Net Increase (Decrease) in Cash and Cash Equivalents	\$ (2,749,827)	\$ 1,667,021	\$ 162,154
Cash and Cash Equivalents at Beginning of Year	<u>3,816,107</u>	<u>2,149,086</u>	<u>1,986,932</u>
Cash and Cash Equivalents at End of Year	<u>\$ 1,066,280</u>	<u>\$ 3,816,107</u>	<u>\$ 2,149,086</u>
<i>Supplemental Disclosures of Cash Flows Information:</i>			
Cash paid during year for interest, net of amounts capitalized	\$ 25,763,169	\$ 19,189,822	\$ 12,207,205
Cash paid during year for income taxes	\$ 129,738	\$ 2,500	\$ 441,926
<i>Non-Cash Financing Activity:</i>			
Issuance of common stock in acquisitions	\$ ---	\$ 8,116,200	\$ ---

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy Company and our wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on 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 ventures and affiliated oil and gas partnerships 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. Significant estimates include proved reserve volumes, DD&A, and deferred income taxes.

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 and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2003, 2002, and 2001, such internal costs capitalized totaled \$11.5 million, \$10.7 million, and \$11.6 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2003, 2002, and 2001, capitalized interest on unproved properties totaled \$6.8 million, \$7.0 million, and \$6.3 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

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

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

We compute the provision for depreciation, depletion, and amortization of oil and gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and capitalized asset retirement obligations, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis. Our amortization per Mcfe was \$1.17, \$1.11, and \$1.31 in 2003, 2002, and 2001, respectively. 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.

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

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, including gas processing facilities and the fair value of asset retirement obligations, net of related salvage values, deferred income taxes, and excluding the asset retirement obligation liability is limited to the sum of the estimated future net revenues from proved properties, excluding cash outflows from asset retirement obligations, using hedged adjusted 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"). Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end price and thus did not affect prices used in this calculation. This calculation is done on a country-by-country basis for those countries with proved reserves.

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

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.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the differences are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2003, we did not have any material natural gas imbalances.

Accounts Receivable. Included in the total "Accounts receivable" balance, which totaled \$28.6 million and \$20.9 million at December 31, 2003 and 2002, respectively, on the accompanying balance sheet, is approximately \$2.3 million of receivables related to volumes produced from 2001 and 2002 that we were notified, were disputed in early 2003. Accordingly, we did not record a receivable with regard to 2003 volumes. We assess the collectibility of trade and other receivables. Based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2003 and 2002, we had an allowance for doubtful accounts of \$0.8 million and \$0.3 million, respectively. These allowances for doubtful accounts balances have been deducted from the total "Accounts receivable" balances on the accompanying consolidated balance sheet.

Debt issuance costs. 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 Senior Notes due 2009 mature on August 1, 2009, and the balance of their issuance costs at December 31, 2003, was \$2.4 million, net of accumulated amortization of \$1.1 million. The issuance costs associated with our revolving credit facility, which was extended 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, 2003, was \$0.6 million, net of accumulated amortization of \$1.3 million. The Senior Notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2003, was \$5.0 million, net of accumulated amortization of \$0.6 million.

Limited Partnerships. At year-end 2003, we serve as managing general partner for six drilling partnerships, and during fiscal 2003 less than 1% of our total oil and gas sales was attributable to our interests in those partnerships. These six partnerships were formed between 1996 and 1998, and will continue to operate until their limited partners vote otherwise.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value 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 requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Hedges that do not meet the criteria for special hedge accounting are accounted for under mark to market 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 price floors and collars. Upon adoption of SFAS No. 133 on January 1, 2001, we recorded a net of taxes charge of \$0.4 million, which is recorded as a Cumulative Effect of Change in Accounting Principle. During 2003, 2002 and 2001, we recognized net losses (gains) of \$2.8 million, \$0.2 million and (\$1.2) million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2003, the Company had recorded \$0.3 million, net of taxes of \$0.2 million, 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 2003 and 2002 was not material. The Company expects to reclassify all amounts currently held in "Other comprehensive loss" into the statement of income within the next six months when the forecasted sale of hedged production occurs.

As of December 31, 2003, we had in place natural gas price floors in effect for the January 2004 contract month through the June 2004 contract, which cover our domestic natural gas production for January 2004 to June 2004. The natural gas price floors cover notional volumes of 3,300,000 Mmbtu with a weighted average floor price of \$4.77. When we entered into these transactions, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of 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 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 reclassified from Other Comprehensive Income (Loss) and recorded in "Price-risk management and other, net" on the consolidated statement of income. The fair value of our derivatives are computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2003, was \$0.5 million and is recognized on the balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our working interest share on wells where we have a 100% working interest. These supervision fees are

recorded as a reduction to general and administrative expenses and oil and gas production expenses based on our estimate of the costs incurred to operate the wells. Effective October 1, 2003, we began recording the supervision fee as a reduction to general and administrative expense only. The total amount of supervision fees charged to the wells we operate was \$5.1 million in 2003, \$5.3 million in 2002, and \$6.8 million in 2001.

Inventories. Inventories consist principally of tubular goods and equipment, stated at the lower of weighted-average cost or market, and oil produced but not sold, stated at the lower of cost (a combination of production costs and depreciation, depletion and amortization expense) or market.

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.

Accounts Payable and Accrued Liabilities. Included in accounts payable and accrued liabilities at December 31, 2003 and 2002 are liabilities of approximately \$11.9 million and \$8.4 million, respectively, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in the applicable bank accounts.

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

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. During 2003, oil and gas sales to Shell, both domestically and in New Zealand, were \$31.1 million, or 15% of total oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were \$23.5 million, or 11.2% of total oil and gas sales. During 2002, oil and gas sales to Eastex Crude Company were \$25.4 million, or 18.0% of total oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were \$14.6 million, or 10.3% of total oil and gas sales. During 2001, oil and gas sales to Eastex Crude Company were \$31.6 million, or 18.1% of total oil and gas sales, while sales to subsidiaries of Enron were \$18.2 million, or 10.4% of total oil and gas sales. 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. In 2001, we discontinued sales of oil and gas to Enron and are selling that production to other purchasers. Credit losses in 2002 and 2003 have been immaterial.

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

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

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2003 and 2002, 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 \$135.6 million and \$129.0 million at December 31, 2003 and 2002, respectively. Based upon quoted market prices as of December 31, 2003 and 2002, the fair values of our Senior Notes due 2012 were \$218.0 million and \$189.2 million, respectively. The carrying value of our Senior Notes due 2009 was \$124.4 million and \$124.3 million at December 31, 2003 and 2002, respectively. The carrying value of our Senior Notes due 2012 was \$200.0 million at both December 31, 2003 and 2002.

Other Comprehensive Loss. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2003, we recorded \$0.3 million, net of taxes of \$0.2 million, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2003 were as follows:

	<u>Gross Value</u>	<u>Tax Effect</u>	<u>Net of Tax Value</u>
Balance at December 31, 2002	\$ 278,208	\$ 100,155	\$ 178,053
Change in fair value of cash flow hedges	2,488,136	895,729	1,592,407
Effect of cash flow hedges settled during the period	<u>(2,345,497)</u>	<u>(844,379)</u>	<u>(1,501,118)</u>
Balance at December 31, 2003	<u>\$ 420,847</u>	<u>\$ 151,505</u>	<u>\$ 269,342</u>

Total comprehensive income was \$29.8 million and \$11.7 million for 2003 and 2002, respectively. Total comprehensive loss was \$22.3 million in 2001.

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; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," our net income (loss) and earnings (loss) per share would have been adjusted to the following pro forma amounts:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Net Income (Loss):			
As Reported	\$29,893,812	\$11,923,227	\$(22,347,765)
Stock-based employee compensation expense determined under fair value method for all awards, net of tax	<u>(4,112,455)</u>	<u>(4,451,799)</u>	<u>(4,284,859)</u>
Pro Forma	<u>\$25,781,357</u>	<u>\$7,471,428</u>	<u>\$(26,632,624)</u>
Basic EPS:			
As Reported	\$1.09	\$.45	\$(0.90)
Pro Forma	\$0.94	\$.28	\$(1.08)
Diluted EPS:			
As Reported	\$1.08	\$.45	\$(0.90)
Pro Forma	\$0.94	\$.27	\$(1.08)

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 2003, 2002, and 2001, respectively: no dividend yield; expected volatility factors of 34.71%, 73.72%, and 46.9%; risk-free interest rates of 4.63%, 4.74%, and 5.24%; and expected lives of 7.2, 7.4, and 7.3 years.

Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of

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

Asset Retirement Obligation recorded as of January 1, 2003	\$	8,934,320
Accretion expense for 2003		857,356
Liabilities incurred for new wells and facilities construction		608,166
Reductions due to sold and abandoned wells		(443,391)
Revisions in estimated cash flows		67,511
Increase due to currency exchange rate fluctuations		113,511
Asset Retirement Obligation as of December 31, 2003	<u>\$</u>	<u>10,137,473</u>

The pro forma effect for 2001, assuming adoption of SFAS No. 143 effective January 1, 2001, would have included a non-cash charge of \$2.6 million (net of \$1.5 million of deferred taxes), which would have been recorded as a Cumulative Effect of Change in Accounting Principle and recognition of an asset retirement obligation of \$4.3 million. The following table displays our pro forma results for the years ended December 31, 2002 and 2001, had we adopted SFAS No. 143 effective January 1, 2001.

	Year Ended December 31, 2002	(Unaudited) Year Ended December 31, 2001
Net Income (Loss):		
Actual – as reported	\$ 11,923,227	\$ (22,347,765)
Pro Forma	\$ 11,515,205	\$ (25,246,667)
Basic EPS:		
Actual – as reported	\$ 0.45	\$ (0.90)
Pro Forma	\$ 0.44	\$ (1.02)
Diluted EPS:		
Actual – as reported	\$ 0.45	\$ (0.90)
Pro Forma	\$ 0.43	\$ (1.02)

New Accounting Pronouncements. In June 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Intangible Assets." We adopted these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires that all business combinations initiated after June 30, 2001, be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and other indefinite lived intangible assets are not amortized but reviewed annually for impairment.

An issue has arisen for companies engaged in oil and gas exploration and production regarding the application of SFAS No. 141 and SFAS No. 142 as they relate to mineral rights held under lease or other contractual arrangements, and as to whether costs associated with these rights should be classified as intangible assets on the balance sheet, apart from other capitalized oil and gas property costs, and to provide specific footnote disclosure. We understand that the Emerging Issues Task Force of the FASB has placed this issue on its agenda, although the date and outcome of the resolution of the issue is unknown.

Historically, we have classified our oil and gas mineral rights held under lease as tangible assets along with our other oil and gas properties, which is in accordance with the Securities and Exchange Commission's ("SEC") full cost accounting rules, and we intend to continue to do so until further guidance is provided. We have estimated the amount associated with these mineral rights using historical depletion rates, estimates of the timing of impairment of unproved properties and assuming the cost for the mineral rights was unaffected by the ceiling test write-down recorded in December 2001 because we cannot associate the ceiling test write-down with particular types of costs. Based on these limitations and assumptions, we estimate the net cost of mineral rights that would be reclassified from oil and gas properties to intangible assets to be approximately \$55-60 million at December 31, 2003 and approximately \$45-50 million at December 31, 2002. These amounts are from July 1, 2001 (the date we adopted SFAS No. 141) to December 31, 2003 as we are not able to calculate amounts to reclassify before that period as our property records did not break out that information. Only our balance sheet accounts would be affected by the reclassification, and our results of operations and cash flows would not be materially impacted by any such reclassification. These mineral rights would continue to be amortized in accordance with full cost accounting rules for oil and gas companies provided in SEC Regulation S-X Rule 4-10. We also do not believe classifying these assets as intangible would have any impact on our compliance with covenants under our debt agreements.

In November 2002, the FASB issued Interpretation No. 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarified that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and initial measurement provisions of this Interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The Company adopted this pronouncement upon the FASB's issuance and the implementation had no impact on the consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46 (Revised December 2003), Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 Consolidated Financial Statements (the "Interpretation"). The Interpretation significantly changes whether entities included in its scope are consolidated by their sponsors, transferors, or investors. The Interpretation introduces a new consolidation model-the variable interest model; which determines control (and consolidation) based on potential variability in gains and losses of the entity being evaluated for consolidation. The Interpretation provides guidance for determining whether an entity lacks sufficient equity or its equity holders lack adequate decision-making ability. These variable interest entities ("VIEs") are covered by the Interpretation and are to be evaluated for consolidation based on their variable interests. These provisions apply immediately to variable interests in VIEs created after January 31, 2003, and to variable interests in special purpose entities for periods ending after December 15, 2003. The provisions apply for all other types of variable interests in VIEs for periods ending after March 15, 2004. We have no variable interests in VIEs created after January 31, 2003, nor do we have variable interests in special purpose entities. The effect of applying the Interpretation is to be reported as the cumulative effect of an accounting change. We have not completed the process of evaluating the effects that will result from adopting the Interpretation.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." This statement sets standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. This statement is effective for periods ending after December 15, 2003. The impact of recognizing this statement was not material for the Company.

2. Earnings Per Share

Basic EPS has been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share for all periods also assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2003, 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, 2003, 2002, and 2001:

	2003			2002			2001		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Loss	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and									
Share Amounts	\$ 29,893,812	27,357,579	\$ 1.09	\$ 11,923,227	26,382,906	\$ 0.45	\$ (22,347,765)	24,732,099	\$ (0.90)
Dilutive Securities:									
Stock Options	--	203,360		--	372,700		--	--	
Diluted EPS:									
Net Income (Loss) and									
Assumed Share									
Conversions	\$ 29,893,812	27,560,939	\$ 1.08	\$ 11,923,227	26,755,606	\$ 0.45	\$ (22,347,765)	24,732,099	\$ (0.90)

Options to purchase approximately 3.2 million shares at an average exercise price of \$16.37 were outstanding at December 31, 2003. Approximately 1.7 million, 1.3 million, and 0.8 million options to purchase shares were not included in the computation of Diluted EPS for the year ended December 31, 2003, 2002, and 2001, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods.

3. Provision for Income Taxes

Income before taxes is as follows:

	Year Ended December 31,		
	2003	2002	2001
United States	\$ 38,955,404	\$ 12,889,583	\$ (35,427,252)
Foreign	11,783,773	5,518,706	1,234,919
Total	\$ 50,739,177	\$ 18,408,289	\$ (34,192,333)

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

	Year Ended December 31,		
	2003	2002	2001
Current	\$ 164,284	\$ 2,338	\$ 114,611
Deferred - Domestic	14,386,868	4,870,239	(12,759,570)
- Foreign	1,917,362	1,612,485	407,523
Total Deferred	16,304,230	6,482,724	(12,352,047)

Total	\$	16,468,514	\$	6,485,062	\$	(12,237,436)
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The differences between income taxes computed using the federal statutory rate of 35% and our effective income tax rates (32.5%, 35.2%, and 35.8% for 2003, 2002, and 2001, respectively), are primarily the result of the currency exchange rate effect on foreign deferred income taxes, state income taxes and foreign income taxes (New Zealand's statutory rate is 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. 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.

SENZ uses the U.S. Dollar as its functional currency for financial reporting purposes, but income taxes are paid in the New Zealand Dollar. Because of the difference in currencies used for financial reporting and tax, there is potential for significant exchange impact on the tax provision calculation. Due to the strengthening of the New Zealand Dollar vs. the U.S. Dollar in 2003, the U.S. Dollar value of the deferred tax assets in New Zealand increased, resulting in favorable adjustment of \$2.9 million compared to the 33% New Zealand statutory rate.

During 2003 the Company increased its provision for state income taxes by \$1.2 million, primarily due to its increased level of business activity in Louisiana. The company calculates its Louisiana income tax using the "apportionment" accounting method. Under apportionment accounting, total federal taxable income is allocated based on the proportional level of U.S. business activity within the state. Due to the relative increase in the Company's domestic activity conducted in Louisiana, the Company increased its estimate of future Louisiana taxable income that will result from the reversal of prior years' timing differences.

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

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Income taxes computed at U.S. statutory rate	\$ 17,758,712	\$ 6,442,901	\$ (11,967,317)
State tax provisions, net of federal benefits	373,992	323,902	(279,875)
Effect of foreign operations	(235,675)	(110,374)	(24,698)
Currency remeasurement gain on foreign tax asset	(2,893,655)	(208,688)	---
Change in estimate for deferred Louisiana income taxes	1,216,105	---	---
Other, net	249,035	37,321	34,454
Provision (benefit) for income taxes	<u>\$ 16,468,514</u>	<u>\$ 6,485,062</u>	<u>\$ (12,237,436)</u>

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2003 and 2002, were as follows:

	<u>2003</u>	<u>2002</u>
Deferred tax assets:		
Alternative minimum tax credits (Domestic)	\$(1,979,399)	\$(1,979,399)
Carryover items (Domestic)	(53,036,919)	(51,174,237)
Acquired deferred tax asset (Foreign)	(3,802,435)	(4,753,044)
Carryover Items (Foreign)	<u>(28,294,320)</u>	<u>(19,494,129)</u>
Total deferred tax assets	<u>\$(87,113,073)</u>	<u>\$(77,400,809)</u>
Deferred tax liabilities		
Domestic oil and gas exploration and development costs	\$98,010,617	\$83,361,520
Foreign oil and gas exploration and development costs	30,190,846	21,566,588
Other	<u>504,383</u>	<u>568,634</u>

Total deferred tax liabilities	\$128,705,846	\$105,496,742
Net deferred tax liabilities	<u>\$41,592,773</u>	<u>\$28,095,933</u>

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 \$4.9 million. The asset is being amortized over the period in which the tax amortization is deducted. The remaining asset value at December 31, 2003, is \$3.8 million. The other foreign carryover asset is attributable to cumulative New Zealand net operating losses. New Zealand tax net operating losses do not expire.

At December 31, 2003, the Company had alternative minimum tax credits of \$2.0 million that carry forward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the alternative minimum tax otherwise due.

The domestic deferred tax carryover items are attributable to expected future tax benefits in the amounts of \$44.9 million for federal net operating losses, \$1.5 million for State of Louisiana net operating losses and \$6.5 million for capital losses. At December 31, 2003, cumulative federal net operating losses were \$128.1 million, which will expire between 2018 and 2022. Louisiana net operating losses total \$44.1 million and will expire between 2013 and 2018.

The Company has not recorded any valuation allowance against the deferred tax assets attributable to net operating loss carryovers at December 31, 2003 and 2002, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts.

In 2002 we recognized a capital loss of approximately \$18.6 million as the result of the liquidation of our partnerships. This loss can only be utilized to offset capital gains and will expire in 2007. The Company plans to sell 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 capital gains from these dispositions, the sales proceeds must exceed the Company's total investment in the properties. Company management has identified several qualified properties it intends to sell that 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.

4. Long-Term Debt

Our long-term debt as of December 31, 2003 and 2002, is as follows:

	<u>2003</u>	<u>2002</u>
Bank Borrowings	\$ 15,900,000	\$ ---
Senior Notes due 2009	124,354,783	124,271,973
Senior Notes due 2012	200,000,000	200,000,000
Long-Term Debt	<u>\$ 340,254,783</u>	<u>\$ 324,271,973</u>

Bank Borrowings. At December 31, 2003, we had \$15.9 million in outstanding borrowings under our \$300.0 million credit facility with a syndicate of ten banks that has a borrowing base of \$250.0 million and expires in October 2005. At December 31, 2002, we had no outstanding borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.00% at December 31, 2003) 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 \$15.9 million borrowed at December 31, 2003, \$15.5 million was borrowed at the LIBOR rate plus applicable margin, which averaged 2.41%.

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 or repurchasing our Senior Notes. 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 and increased to \$250.0 million effective November 1, 2003, an increase of \$55.0 million from the previous level of \$195.0 million. We requested that the commitment amount with our bank group be reduced to \$150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in May 2004.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled \$1.6 million in 2003, \$3.6 million in 2002, and \$5.8 million in 2001. The amount of commitment fees included in interest expense was \$0.6 million in both 2003 and 2002 and \$0.3 million in 2001.

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 borrowings. 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. The terms of these Senior Notes include, among other restrictions, a limit on repurchases by Swift of its common stock. 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 \$13.2 million in both 2003 and 2002, and \$13.1 million in 2001.

Senior Notes Due 2012. Our Senior Notes due 2012 consist of \$200.0 million 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. The terms of these Senior Notes include, among other restrictions, a limit on repurchases by Swift of its common stock. 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 \$19.1 million in 2003 and \$13.5 million in 2002.

The aggregate maturities on our long-term debt are \$0, \$15.9 million, \$0, \$0, and \$0, and \$325.0 million for 2004, 2005, 2006, 2007, 2008, and thereafter, respectively.

We have capitalized interest on our unproved properties in the amount of \$6.8 million, \$7.0 million, and \$6.3 million, in 2003, 2002, and 2001, respectively.

5. Commitments and Contingencies

Total rental and lease expenses were \$2.2 million in 2003, \$1.9 million in 2002, and \$1.3 million in 2001 and are included in "General and administrative, net" on our consolidated statements of income. Our remaining minimum annual obligations under non-cancelable operating lease commitments are \$2.1 million for 2004, \$0.5 million for 2005, \$0.2 million for 2006, \$0.2 million for 2007, \$0.1 million in 2008, and less than \$0.1 million thereafter or \$3.1 million in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas, and in New Zealand.

In the ordinary course of business, we have entered into agreements with 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 \$0.1 million accrued in "Accounts payable and accrued liabilities" at December 31, 2003, on the accompanying balance sheet related to these commitments.

In the ordinary course of business, we have entered into agreements with drilling and seismic contractors for such services. The remaining commitments at December 31, 2003 for these services totaled \$5.9 million and these services are expected to be provided in 2004.

As of December 31, 2003, 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.

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 consolidated financial position or results of operations of Swift.

6. Stockholders' Equity

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

Stock-Based Compensation Plans. We have two current stock option plans, the 2001 Omnibus Stock Compensation Plan, which was adopted by our board of directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified 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 56,574 shares at a price range of \$6.80 to \$11.85 in 2003, 9,801 shares at a price of \$12.47 in 2002, and 22,360 shares at a price of \$21.41 in 2001. The estimated weighted average fair value of shares issued under this plan, as

determined using the Black-Scholes option-pricing model, was \$1.75 in 2003, \$1.92 in 2002, and \$8.19 in 2001. As of December 31, 2003, 296,053 shares remained available for issuance under this plan.

The following is a summary of our stock options under these plans as of December 31, 2003, 2002, and 2001:

	2003		2002		2001	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	3,018,505	\$ 16.64	2,639,504	\$ 17.44	2,076,593	\$ 11.70
Options granted	504,014	\$ 13.20	585,055	\$ 12.32	747,073	\$ 31.51
Options canceled	(110,901)	\$ 21.02	(84,254)	\$ 23.37	(31,247)	\$ 14.09
Options exercised	(173,007)	\$ 8.85	(121,800)	\$ 8.61	(152,915)	\$ 8.69
Options outstanding, end of period	<u>3,238,611</u>	\$ 16.37	<u>3,018,505</u>	\$ 16.64	<u>2,639,504</u>	\$ 17.44
Options exercisable, end of period	<u>1,714,789</u>	\$ 15.00	<u>1,480,490</u>	\$ 13.71	<u>1,181,141</u>	\$ 11.49
Options available for future grant, end of period	<u>494,925</u>		<u>419,845</u>		<u>1,155,057</u>	
Estimated weighted average fair value per share of options granted during the year	<u>\$6.93</u>		<u>\$9.55</u>		<u>\$20.68</u>	

The following table summarizes information about stock options outstanding at December 31, 2003:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding at 12/31/03	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable At 12/31/03	Wtd. Avg. Exercise Price
\$ 7.00 to \$17.99	2,301,259	6.2	\$ 11.04	1,224,119	\$ 9.67
\$18.00 to \$28.99	246,111	4.7	\$ 22.79	195,911	\$ 22.88
\$29.00 to \$ 41.00	691,241	7.2	\$ 31.82	294,759	\$ 31.89
\$ 7.00 to \$ 41.00	<u>3,238,611</u>	6.3	\$ 16.37	<u>1,714,789</u>	\$ 15.00

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, 2003, 2002, and 2001, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled \$0.2 million for the years ended December 31, 2003, 2002, and 2001 and are recorded as “General and administrative, net” on the accompanying consolidated statements of income.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were \$0.6 million for each of the years ended December 31, 2003, 2002, and 2001 and are recorded as “General and administrative, net” on the accompanying consolidated statements of income. The contributions in 2003, 2002, and 2001 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 34,280, 64,490, and 28,798 shares for the 2003, 2002, and 2001 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, 2003, 527,018 shares remain in treasury (net of 400,756 shares used to fund ESOP, 401(k) contributions and

acquisitions) with a total cost of \$7.6 million 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. In accordance with the partnership agreements, operating fees charged to the partnerships in 2003, 2002, and 2001 totaled approximately \$0.2 million, \$0.3 million, and \$1.0 million, 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 \$0.4 million, \$1.0 million, and \$3.1 million in 2003, 2002, and 2001, 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, totaling less than \$0.1 million, \$0.5 million, and \$2.4 million in 2003, 2002, and 2001, respectively.

8. Foreign Activities

As of December 31, 2003, our gross capitalized oil and gas property costs in New Zealand totaled approximately \$205.3 million. Approximately \$169.5 million has been included in the proved properties portion of our oil and gas properties, while \$35.8 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. These assets fit strategically with our existing assets in New Zealand. This acquisition was accounted for by the purchase method of accounting. The revenues and expenses from these TAWN properties have been included in our consolidated statements of income from the date of acquisition forward. In conjunction with this TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which included our Rimu 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.

10. Segment Information

The Company has two reportable segments that are in the business of crude oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. The Company evaluates performance based on profit or loss from oil and gas operations before other revenues, general and administrative expenses, and interest expense, net. The Company's reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	2003		
	Domestic	New Zealand	Total
Oil and gas sales	\$ 164,167,390	\$ 46,865,249	\$ 211,032,639
Costs and Expenses:			
Depreciation, depletion, and amortization	(44,645,939)	(18,426,118)	(63,072,057)
Accretion of asset retirement obligation	(623,948)	(233,408)	(857,356)
Oil and gas production	(39,313,081)	(13,553,721)	(52,866,802)
Income from oil and gas operations	\$ 79,584,422	\$ 14,652,002	\$ 94,236,424
Other revenues (1)			(2,131,656)
General and administrative, net			(14,097,066)
Interest expense, net			<u>(27,268,524)</u>
Income before Income Taxes and Cumulative Effect of Change in Accounting Principle			\$ <u>50,739,178</u>
Property and Equipment, net	\$ <u>642,019,661</u>	\$ <u>174,440,115</u>	\$ <u>816,459,776</u>
	2002		
	Domestic	New Zealand	Total
Oil and gas sales	\$ 112,065,003	\$ 29,130,710	\$ 141,195,713
Costs and Expenses:			
Depreciation, depletion, and amortization	(43,660,843)	(12,563,549)	(56,224,392)
Oil and gas production	(33,088,958)	(8,408,354)	(41,497,312)
Income from oil and gas operations	\$ 35,315,202	\$ 8,158,807	\$ 43,474,009
Other revenues (1)			8,774,098
General and administrative, net			(10,564,849)
Interest expense, net			<u>(23,274,969)</u>
Income before Income Taxes and Cumulative Effect of Change in Accounting Principle			\$ <u>18,408,289</u>
Property and Equipment, net	\$ <u>565,149,393</u>	\$ <u>160,360,061</u>	\$ <u>725,509,454</u>

	2001		
	(Unaudited)	(Unaudited)	
	Domestic	New Zealand	Total
Oil and gas sales	\$ 179,360,844	\$ 1,823,791	\$ 181,184,635
Costs and Expenses:			
Depreciation, depletion, and amortization	(59,318,768)	(183,272)	(59,502,040)
Oil and gas production	(36,554,418)	(165,191)	(36,719,609)
Write-down of oil and gas properties	<u>(98,862,247)</u>	---	<u>(98,862,247)</u>
Income from oil and gas operations	\$ (15,374,589)	\$ 1,475,328	\$ (13,899,261)
Other revenues (1)			2,622,855
General and administrative, net			(8,186,654)
Other expenses			(2,102,251)
Interest expense, net			<u>(12,627,022)</u>
Income before Income Taxes and Cumulative Effect of Change in Accounting Principle			\$ <u>(34,192,333)</u>
Property and Equipment, net	<u>\$ 547,232,724</u>	<u>\$ 83,975,947</u>	<u>\$ 631,208,671</u>

(1) Other revenues consist of Fees from affiliated limited partnerships, Interest income, Gain on asset disposition, Price-risk management and other, net, on the accompanying consolidated statements of income.

Supplemental Information (Unaudited)

Swift Energy Company and Subsidiaries

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

	Total	Domestic	New Zealand
December 31, 2003:			
Proved oil and gas properties	\$ 1,305,763,355	\$ 1,136,267,890	\$ 169,495,465
Unproved oil and gas properties	67,557,969	31,802,621	35,755,348
	1,373,321,324	1,168,070,511	205,250,813
Accumulated depreciation, depletion, and amortization	(560,961,013)	(529,272,658)	(31,688,355)
Net capitalized costs	<u>\$ 812,360,311</u>	<u>\$ 638,797,853</u>	<u>\$ 173,562,458</u>
December 31, 2002:			
Proved oil and gas properties	\$ 1,150,633,802	\$ 1,005,583,492	\$ 145,050,310
Unproved oil and gas properties	69,603,481	41,850,890	27,752,591
	1,220,237,283	1,047,434,382	172,802,901
Accumulated depreciation, depletion, and amortization	(498,619,342)	(485,289,654)	(13,329,688)
Net capitalized costs	<u>\$ 721,617,941</u>	<u>\$ 562,144,728</u>	<u>\$ 159,473,213</u>

Of the \$31,802,621 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2003, excluded from the amortizable base, \$8,350,017 was incurred in 2003, \$7,952,698 was incurred in 2002, \$7,294,531 was incurred in 2001, and \$8,205,375 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 \$35,755,348 of New Zealand unproved property costs at December 31, 2003, excluded from the amortizable base, \$9,309,694 was incurred in 2003, \$17,593,162 was incurred or acquired in 2002, \$2,644,091 was incurred in 2001, and \$6,208,401 was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there within a two to four year time frame.

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

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

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

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

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

¹These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2003, 2002, and 2001 were \$20,702,276, \$23,454,234, and \$22,470,263, respectively.

²Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately \$11.5 million, \$10.7 million, and \$11.6 million in 2003, 2002, and 2001, respectively. In addition, total includes \$6.9 million, \$7.0, and \$6.3 million in 2003, 2002, and 2001, respectively, of capitalized interest on unproved properties.

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

Results of Operations.

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Oil and gas sales	\$ 211,032,639	\$ 164,167,390	\$ 46,865,249
Oil and gas production costs	(52,866,802)	(39,313,081)	(13,553,721)
Depreciation and depletion	(62,037,680)	(43,818,709)	(18,218,971)
Accretion of asset retirement obligation	(857,356)	(623,948)	(233,408)
	95,270,801	80,411,652	14,859,149
Provision for income taxes	32,321,635	29,696,023	2,625,612
Results of producing activities	\$ 62,949,166	\$ 50,715,629	\$ 12,233,537
Amortization per physical unit of production (equivalent Mcf of gas)	\$ 1.17	\$ 1.30	\$ 0.94

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Oil and gas sales	\$ 141,195,713	\$ 112,065,003	\$ 29,130,710
Oil and gas production costs	(41,497,312)	(33,088,958)	(8,408,354)
Depreciation and depletion	(55,254,467)	(42,807,364)	(12,447,103)
	44,443,934	36,168,681	8,275,253
Provision for income taxes	15,860,064	13,129,231	2,730,833
Results of producing activities	\$ 28,583,870	\$ 23,039,450	\$ 5,544,420
Amortization per physical unit of production (equivalent Mcf of gas)	\$ 1.11	\$ 1.25	\$ 0.80

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

These results of operations do not include the losses (gains) from our hedging activities of \$2.8 million, \$0.2 million and (\$1.2) million for 2003, 2002 and 2001, respectively.

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

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

Supplemental Reserve Information. The following information presents estimates of our proved oil and gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. (“Gruy”), independent petroleum consultants. Gruy’s audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy’s audit was based upon review of production histories and other geological, economic, and engineering data provided by Swift. Where Gruy had material disagreements with Swift reserve estimates, we revised our estimates to be in agreement. Gruy’s report dated January 23, 2004, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2003, and includes definitions and assumptions that served as the basis for the audit of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

Estimates of Proved Reserves

	Total		Domestic		New Zealand	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)
Proved reserves as of December 31, 2000	418,613,976	35,133,596	363,300,499	23,942,709	55,313,477	11,190,887
Revisions of previous estimates ¹	(122,127,541)	5,621,556	(101,693,477)	8,460,690	(20,434,064)	(2,839,134)
Purchases of minerals in place	10,038,803	7,430,591	10,038,803	7,430,591	--	--
Sales of minerals in place	(7,508,064)	(555,586)	(7,508,064)	(555,586)	--	--
Extensions, discoveries, and other additions	52,353,909	8,907,852	50,810,697	6,257,441	1,543,212	2,650,411
Production	(26,458,958)	(3,055,373)	(26,458,958)	(2,971,112)	--	(84,261)
Proved reserves as of December 31, 2001	324,912,125	53,482,636	288,489,500	42,564,733	36,422,625	10,917,903
Revisions of previous estimates ¹	(29,972,714)	5,298,439	(29,470,419)	8,675,082	(502,295)	(3,376,643)
Purchases of minerals in place	51,940,044	3,711,948	226,245	24,207	51,713,799	3,687,741
Sales of minerals in place	(3,839,124)	(464,490)	(3,839,124)	(464,490)	--	--
Extensions, discoveries, and other additions	10,822,919	12,180,558	197,919	11,304,782	10,625,000	875,776
Production	(27,131,578)	(3,770,128)	(15,780,059)	(3,074,674)	(11,351,519)	(695,454)
Proved reserves as of December 31, 2002	326,731,672	70,438,963	239,824,062	59,029,640	86,907,610	11,409,323
Revisions of previous estimates ¹	(6,445,114)	4,975,920	(1,418,312)	3,497,022	(5,026,802)	1,478,898
Purchases of minerals in place	273,623	35,472	273,623	35,472	--	--
Sales of minerals in place	(3,984,209)	(228,505)	(3,984,209)	(228,505)	--	--
Extensions, discoveries, and other additions	47,231,609	9,730,665	21,370,151	8,018,766	25,861,458	1,711,899
Production	(28,002,719)	(4,192,612)	(13,744,040)	(3,336,702)	(14,258,679)	(855,910)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015,693	93,483,587	13,744,210
Proved developed reserves: ²						
December 31, 2000	215,169,833	10,980,196	215,169,833	10,980,196	--	--
December 31, 2001	181,651,578	23,759,574	167,401,736	20,393,142	14,249,842	3,366,432
December 31, 2002	233,514,572	35,928,395	149,731,562	26,530,112	83,783,010	9,398,283
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767,983	71,946,586	6,757,383

¹Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2003, were based upon hedge adjusted prices in effect at year-end. Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end price and thus did not affect prices used in these calculations. The weighted average of 2003 year-end prices for total, domestic, and New Zealand were \$4.56, \$5.53, and \$2.04 per Mcf of natural gas, \$30.16, \$30.88, and \$26.78 per barrel of oil, and \$20.61, \$21.81 and \$14.10 per barrel of NGL, respectively. This compares to \$3.49, \$4.23, and \$1.48 per Mcf, \$29.27, \$29.36, and \$28.80 per barrel of oil, and \$16.54, \$17.30 and \$12.24 per barrel of NGL as of December 31, 2002, for total, domestic, and New Zealand, respectively. The weighted average of 2001 year-end prices for total, domestic, and New Zealand were \$2.51, \$2.68, and \$1.18 per Mcf of natural gas, \$18.45, \$18.51, and \$18.25 per barrel of oil, and \$10.70, \$11.00, and \$8.90 per barrel of NGL, respectively.

²At December 31, 2003, 59% of our reserves were proved developed, compared to 60% at December 31, 2002, 50% at December 31, 2001, and 45% at December 31, 2000.

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

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

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Future gross revenues	\$ 1,706,475,138	\$ 1,485,480,927	\$ 220,994,211
Future production costs	(483,588,857)	(436,141,429)	(47,447,428)
Future development costs	(198,172,628)	(185,347,628)	(12,825,000)
Future net cash flows before income taxes	1,024,713,653	863,991,870	160,721,783
Future income taxes	(261,635,331)	(208,726,729)	(52,908,602)
Future net cash flows after income taxes	763,078,322	655,265,141	107,813,181
Discount at 10% per annum	(308,520,417)	(274,882,174)	(33,638,243)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	\$ 454,557,905	\$ 380,382,967	\$ 74,174,938

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

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

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

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

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

The estimates of cash flows and reserves quantities shown above are based on year-end hedge adjusted oil and gas prices for each period and do not include the effects of our hedging activities. Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end price and thus did not affect prices used in these calculations. Subsequent changes to such year-end oil and gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the Consolidated Financial Statements). Application of these rules during periods of relatively low oil and gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

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

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

	Year Ended December 31,		
	2003	2002	2001
Beginning balance	\$ 836,869,791	\$ 454,557,905	\$ 1,577,958,466
Revisions to reserves proved in prior years--			
Net changes in prices, production costs, and future development costs	109,501,730	373,890,614	(1,692,627,074)
Net changes due to revisions in quantity estimates	48,194,999	2,582,633	(93,669,181)
Accretion of discount	116,136,717	60,298,619	231,325,481
Other	(57,822,716)	(88,675,455)	(204,768,815)
Total revisions	216,010,730	348,096,411	(1,759,739,589)
New field discoveries and extensions, net of future production and development costs	243,183,114	190,461,371	110,213,160
Purchases of minerals in place	1,019,290	76,538,437	39,544,163
Sales of minerals in place	(13,660,012)	(5,769,642)	(50,131,970)
Sales of oil and gas produced, net of production costs	(158,165,836)	(99,698,403)	(144,262,145)
Previously estimated development costs incurred	77,404,994	48,752,814	94,107,760
Net change in income taxes	(67,805,536)	(176,069,102)	586,868,060
Net change in standardized measure of discounted future net cash flows	297,986,744	382,311,886	(1,123,400,561)
Ending balance	\$ 1,134,856,535	\$ 836,869,791	\$ 454,557,905

Quarterly Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2002 and 2003:

	Revenues	Income Before Income Taxes, and Change in Accounting Principle ^b	Income Before Change in Accounting Principle ^b	Net Income	Basic EPS Income Before Change In Accounting Principle ^b	Diluted EPS Income Before Change In Accounting Principle ^b	Basic EPS Net Income	Diluted EPS Net Income
2002:								
First ^a	\$ 34,354,077	\$ 4,674,075	\$ 3,019,810	\$ 3,019,810	\$ 0.12	\$ 0.12	\$ 0.12	\$ 0.12
Second	38,570,269	5,518,886	3,584,092	3,584,092	0.13	0.13	0.13	0.13
Third	36,570,809	2,933,350	1,947,006	1,947,006	0.07	0.07	0.07	0.07
Fourth	40,474,656	5,281,978	3,372,319	3,372,319	0.12	0.12	0.12	0.12
Total	<u>\$ 149,969,811</u>	<u>\$ 18,408,289</u>	<u>\$ 11,923,227</u>	<u>\$ 11,923,227</u>	<u>\$ 0.45</u>	<u>\$ 0.45</u>	<u>\$ 0.45</u>	<u>\$ 0.45</u>
2003:								
First	\$ 53,499,993	\$ 16,223,744	\$ 10,484,937	\$ 6,108,085	\$ 0.38	\$ 0.38	\$ 0.22	\$ 0.22
Second	50,717,529	11,073,804	7,221,426	7,221,426	0.26	0.26	0.26	0.26
Third	51,552,522	11,153,368	7,062,625	7,062,625	0.26	0.26	0.26	0.26
Fourth	53,130,939	12,288,262	9,501,676	9,501,676	0.35	0.34	0.35	0.34
Total	<u>\$ 208,900,983</u>	<u>\$ 50,739,178</u>	<u>\$ 34,270,664</u>	<u>\$ 29,893,812</u>	<u>\$ 1.25</u>	<u>\$ 1.24</u>	<u>\$ 1.09</u>	<u>\$ 1.08</u>

^aFirst quarter 2002 results include a gain on asset disposition of \$7,332,668.

^bThere were no extraordinary items in 2002 or 2003.

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

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, 2002, 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 December 31, 2001 and 2000 and for each of the three years ended December 31, 2001 is included in this Form 10-K Report for the year ended December 31, 2003, but such previously issued report has not been reissued.

Item 9A. 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-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") as of the end of the period covered by the 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 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 11, 2004, 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 11, 2004, 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 11, 2004, 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 11, 2004, annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 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 11, 2004, annual shareholders' meeting is incorporated by reference.

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, 2004, and the data contained therein are included in Item 8 hereof:

•Report of Independent Auditors.....	34
•Report of Independent Public Accountants.....	35
•Consolidated Balance Sheets.....	36
•Consolidated Statements of Income.....	37
•Consolidated Statements of Stockholders' Equity.....	38
•Consolidated Statements of Cash Flows.....	39
•Notes to Consolidated Financial Statements.....	40

2. Financial Statement Schedules

[None]

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 through November 5, 2002.
4(a).1 ²	Indenture dated as of July 29, 1999, between Swift Energy Company and Bank One, N.A., as Trustee.
4(a).2 ³	First Supplemental Indenture dated as of August 4, 1999, between Swift Energy Company and Bank One, N.A., 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 One, N.A., as Trustee.
4(a).4 ⁵	First Supplemental Indenture dated as of April 16, 2002, between Swift Energy Company and Bank One, N.A., 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 Plan, as of May 1997.
10.3 ⁶ +	Amended and Restated Swift Energy Company 1990 Stock Compensation Plan, as of May 1997.
10.4 ⁷ +	Amendment to the Swift Energy Company 1990 Stock Compensation, as of May 9, 2002.
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 Energy Company and A. Earl Swift.
10.7 ¹ +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Terry E. Swift.

- 10.8¹ + Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and James M. Kitterman.
- 10.9¹ + Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Bruce H. Vincent.
- 10.10¹ + Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Joseph A. D'Amico.
- 10.11¹ + Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Victor R. Moran.
- 10.13¹ + Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company and Alton D. Heckaman, Jr.
- 10.14⁸ + Fourth Amended and Restated Agreement and Release, by and between Swift Energy Company and Virgil Neil Swift, dated November 20, 2000.
- 10.15⁹ Amended and Restated Rights Agreement between Swift Energy and American Stock Transfer & Trust Company, dated March 31, 1999.
- 10.16¹⁰ Amended and Restated Credit Agreement among Swift Energy Company and Bank One, N.A. as administrative agent, CIBC Inc. as syndication agent and Credit Lyonnais New York Branch and Societe Generale as documentation agents and the lenders signatory hereto dated September 28, 2001.
- 10.17¹¹ First Amendment to Amended and Restated Credit Agreement, effective January 25, 2002 among Swift Energy Company, as Borrower, Bank One, NA as Administrative Agent, CIBC Inc. as Syndication Agent, Credit Lyonnais, New York Branch as Documentation Agent, Societe Generale as Documentation Agent and The Lenders Signatory Hereto and Banc One Capital Markets, Inc. as Sole Lead Arranger and Sole Book Runner.
- 10.18¹¹ Second Amendment to Amended and Restated Credit Agreement, effective April 5, 2002 among Swift Energy Company, as Borrower, Bank One, NA as Administrative Agent, CIBC Inc. as Syndication Agent, Wells Fargo Bank (Texas), National Association as Syndication Agent, Credit Lyonnais, New York Branch as Documentation Agent, Societe Generale as Documentation Agent and The Lenders Signatory Hereto and Banc One Capital Markets, Inc. as Sole Lead Arranger and Sole Book Runner.
- 10.19* Consulting Agreement dated as of October 13, 2003 between Swift Energy Company and Raymond O. Loen.
- 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 regarding Forms S-8 and S-3 Registration Statements.
- 99.1* **The summary of H.J. Gruy and Associates, Inc. report, dated January 23, 2004.**
- 99.2* Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- (b) Reports on Form 8-K filed during the quarter ended December 31, 2003, which are incorporated herein by reference:

On November 5, 2003, the Company filed a Current Report on Form 8-K that reported under Item 7, "Financial Statements and Exhibits" and Item 12, "Results of Operations and Financial Condition" relating to the press release of the announcement of third quarter earnings.

¹ Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-8754.

- ² Incorporated by reference from Exhibit 4.2 to Pre-Effective Amendment No. 1 to Form S-3 Registration Statement No. 33-81651 of Swift Energy Company, filed July 9, 1999, which Exhibit 4.2 is the form of such indenture.
- ³ Incorporated by reference from Swift Energy Company Report on Exhibit 4.1 to Form 8-K dated August 4, 1999, File No. 1-8754.
- ⁴ Incorporated by reference from Swift Energy Company Report on Exhibit 4-1 to Form 8-K dated April 16, 2002, File No. 1-8754.
- ⁵ Incorporated by reference from Swift Energy Company Report on Exhibit 4-2 to Form 8-K dated April 16, 2002, File No. 1-8754.
- ⁶ Incorporated by reference from Swift Energy Company definitive proxy statement for annual shareholders meeting filed April 14, 1997, File No. 1-8754.
- ⁷ Incorporated by reference from Registration Statement No. 333-67242 on Form S-8 filed on August 10, 2001.
- ⁸ Incorporated by reference from Swift Energy Company Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-8754.
- ⁹ Incorporated by reference from Swift Energy Company Amendment No. 1 to Form 8-A, filed April 7, 1999.
- ¹⁰ Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2001, File No. 1-8754.
- ¹¹ Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002, File No. 1-8754.
- ¹² Incorporated by reference from Registration Statement No. 33-60469 on Form S-2 filed on June 22, 1995.
- ¹³ Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2002, File No. 1-8754.

* Filed herewith.

+ Management contract or compensatory plan or arrangement.

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:

A. Earl Swift
Chairman of the Board

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:

<u>Signatures</u>	<u>Title</u>	<u>Date</u>
_____ A. Earl Swift	Chairman of the Board	March 8, 2004
_____ Terry E. Swift	Director Chief Executive Officer President	March 8, 2004
_____ Alton D. Heckaman Jr.	Sr. Vice-President—Finance Principal Financial Officer	March 8, 2004
_____ David W. Wesson	Controller Principal Accounting Officer	March 8, 2004

<hr/> <p>G. Robert Evans</p>	Director	March 8, 2004
<hr/> <p>Raymond E. Galvin</p>	Director	March 8, 2004
<hr/> <p>Greg Matiuk</p>	Director	March 8, 2004
<hr/> <p>Henry C. Montgomery</p>	Director	March 8, 2004
<hr/> <p>Clyde W. Smith, Jr.</p>	Director	March 8, 2004
<hr/> <p>Virgil N. Swift</p>	Director	March 8, 2004
<hr/> <p>Harold J. Withrow</p>	Director	March 8, 2004

CERTIFICATION

I, Terry E. Swift, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2003, of Swift Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) for Swift Energy and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2004

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

