SWIFT ENERGY CO
Form 10-K
February 27, 2009

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, 2008

Commission File Number 1-8754

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

TEXAS	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.
Yes No þ

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 þ 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. [þ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act).

Large accelerated filer	Accelerated filer þ	Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes No þ

1

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold on the New York Stock Exchange as of June 30, 2008, the last business day of June 2008, was approximately $2,011,284,626.

The number of shares of common stock outstanding as of January 31, 2009 was 30,923,267.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 12, 2009	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.		Page
Part I		
Item 1.	Business	4
Item 1A.	Risk Factors	19
Item 1B.	Unresolved Staff Comments	24
Item 2.	Properties	7
Item 3.	Legal Proceedings	26
Item 4.	Submission of Matters to a Vote of Security Holders	26
Part II		
Item 5.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	27
Item 6.	Selected Financial Data	29
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	30
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	43
Item 8.	Financial Statements and Supplementary Data	44
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	78
Item 9A.	Controls and Procedures	78
Item 9B.	Other Information	78
Part III		
Item 10.	Directors, Executive Officers and Corporate Governance (1)	79

Item 11.	Executive Compensation (1)	79
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholders Matters (1)	79
Item 13.	Certain Relationships and Related Transactions, and Director Independence (1)	79
Item 14	Principal Accountant Fees and Services (1)	79
Part IV		
Item 15	Exhibits and Financial Statement Schedules	80

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 12, 2009

PART I

Item 1. Business

See pages 24 and 25 for explanations of abbreviations and terms used herein.

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and natural gas properties, with a focus on oil and natural gas reserves onshore and in the inland waters of Louisiana and Texas. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. In December 2007, we agreed to sell the majority of our New Zealand assets and in 2008 we completed the sale. At year-end, we had estimated proved reserves from our continuing operations of 116.4 MMBoe with a PV-10 of $1.4 billion (PV-10 is a non-GAAP measure, see the section titled “Oil and Natural Gas Reserves” in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). Our total proved reserves at year-end 2008 were comprised of approximately 43% crude oil, 42% natural gas, and 15% NGLs; and 53% of our total proved reserves were proved developed. Our proved reserves are concentrated with 61% of the total in Louisiana, 38% in Texas, and 1% in other states.

We currently focus primarily on development and exploration of fields in four core areas as well as a strategic growth area:

- Southeast Louisiana

Lake Washington field
Bay de Chene field

- South Texas

AWP field
Sun TSH field
Briscoe Ranch field
Las Tiendas field

- Central Louisiana/East Texas

Brookeland field
South Bearhead Creek field
Masters Creek field

- South Louisiana

Horseshoe Bayou/Bayou Sale fields
Jeanerette field
Cote Blanche Island field
Bayou Penchant field

- Strategic Growth

High Island field
Other Areas

Competitive Strengths and Business Strategy

Our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to achieve our goals. Our primary strengths and strategies are set forth below.

Demonstrated Ability to Grow Reserves and Production

We have grown our proved reserves from 107.4 MMBoe to 116.4 MMBoe over the five-year period ended December 31, 2008. Over the same period, our annual production has grown from 5.6 MMBoe to 10.0 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities and acquisitions in our core areas. During 2008, our proved reserves decreased by 13%, due mainly to technical adjustments in two fields and lower prices used in the 2008 computation of reserves. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to continue growing both our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions and strategic opportunities. In general, we focus on drilling in each of our core areas when oil and natural gas prices are strong. When prices weaken and the per unit cost of acquisitions becomes more attractive, or a strategic opportunity exists, we also focus on acquisitions. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. Due mainly to technical adjustments in two fields and lower prices used in the 2008 computation of reserves, we did not replace production during 2008. We have replaced 120% of our production on average over the last five years.

Given the current low oil and gas pricing environment, our 2009 capital expenditures are currently budgeted at $125 million to $150 million, net of minor non-core dispositions and excluding any property acquisitions. Our 2009 capital expenditures are expected to include drilling up to three horizontal wells in the Olmos sands in our AWP field, drilling a well in the Eagle Ford shale formation of our AWP field, drilling an exploratory well in our Southeast Louisiana core area along with completing a pipeline from our existing Shasta well to the Westside facility, facility projects in our Bay de Chene field, recompletions in our Southeast Louisiana core area, and fracture enhancements in our South Texas core area. We also plan to drill up to 10 additional wells to shallow and intermediate depths in our Southeast Louisiana core area.

For 2009, due to our reduced capital budget when compared to previous years, we anticipate a decrease in production volumes from 2008 levels and we do not expect to fully replace reserves produced in 2009.

Replacement of Reserves

Historically we have added proved reserves through both our drilling and acquisition activities. We believe that this strategy will continue to add reserves for us over the long-term; however, external factors beyond our control, such as limited availability of capital or its cost, adverse weather conditions, commodity market factors, and governmental regulations, could limit our ability to drill wells and acquire proved properties in the future. We have included below a listing of the vintages of our proved undeveloped reserves in the table titled “Proved Undeveloped Reserves” and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and natural gas production. Our reserves additions for each year are estimates. Reserves volumes can change over time and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact our ability to access these reserves, such as availability of capital, commodity prices, new and existing government regulations, adverse weather conditions, competition within our industry, the requirement of new or upgraded infrastructure at the production site, and technological advances.

Concentrated Focus on Core Areas with Operational Control

The concentration of our operations in our core areas allows us to leverage our drilling unit and workforce synergies while minimizing the continued escalation of drilling and completion costs. Our average lease operating costs for continuing operations, excluding taxes, were $10.44, $6.68 and $5.29 per Boe in 2008, 2007, and 2006, respectively. Each of our core areas includes properties that are targeted for future growth. This concentration allows us to utilize the experience and knowledge we gain in these areas to continually improve our operations and guide us in developing our future activities and in operating similar type assets. The value of this concentration is enhanced by our operational control of 96% of our proved oil and natural gas reserves base as of December 31, 2008. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital, and time field development.

Develop Under-Exploited Properties

We are focused on applying advanced technologies and recovery methods to areas with known hydrocarbon resources to optimize our exploration and exploitation of such properties as illustrated in our core areas. For instance, the Lake Washington field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily net production from less than 700 Boe to over 13,000 Boe for the quarter ended December 31, 2008. We have also increased our proved reserves in the area from 7.7 million Boe to approximately 31.8 million Boe as of December 31, 2008. When we first acquired our interests in the AWP, Brookeland, and Masters Creek fields, these fields each had significant additional development potential. In December 2004, we acquired our Bay de Chene and Cote Blanche Island fields which hold both proved developed and proved undeveloped reserves and we began our initial development activities of these properties in 2006. In November 2005, we acquired our South Bearhead Creek field and then in October 2006, we acquired interests in five fields in South Louisiana which have significant development potential. In October 2007, we acquired interests in three South Texas properties one in the Maverick Basin (Briscoe Ranch) and two in the Gulf Coast basin (Sun TSH and Las Tiendas) that total approximately 82,000 acres. These properties are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmitt County, and the Las Tiendas field in Webb County. In September 2008, we acquired additional interests in the Briscoe Ranch field within the Briscoe “A” lease in Dimmit County. We intend to continue acquiring large acreage positions where we can grow production by applying advanced technologies and recovery methods using our experience and knowledge developed in our core areas.

Maintain Financial Flexibility and Disciplined Capital Structure

We practice a disciplined approach to financial management and have historically maintained a disciplined capital structure to provide us with the ability to execute our business plan. As of December 31, 2008, our debt to capitalization was approximately 49%, while our debt to proved reserves ratio was $4.99 per Boe, and our debt to PV-10 ratio was 43%. We plan to maintain a capital structure that provides financial flexibility through the prudent use of capital, aligning our capital expenditures to our cash flows, and maintaining a strategic hedging program when appropriate.

Experienced Technical Team and Technology Utilization

We employ 73 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for approximately five years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other related services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We increasingly use advanced technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisitions, pre-stack time and depth image enhancement reprocessing, amplitude versus offset datasets, coherency cubes, and detailed field reservoir depletion planning. In 2004, we performed a 3-D seismic survey covering our Lake Washington field, and in 2006 we carried out a second 3-D survey in and around our Cote Blanche Island field. We now have seismic data covering over 4,000 square miles in South Louisiana that have been merged into two data sets, inclusive of data covering five fields we acquired in 2006. In late 2007, we began to extend this methodology to South Texas and licensed approximately 400 square miles of 3-D seismic data. In 2008, we purchased data from a 3-D seismic survey in the AWP field. As these data are processed, merged with other available seismic data, and integrated with geologic data, we develop proprietary geo-science databases that we use to guide our exploration and development programs.

We use various recovery techniques, including gas lift, water flooding, pressure maintenance, and acid treatments to enhance crude oil and natural gas production. We also fracture reservoir rock through the injection of high-pressure fluid, install gravel packs, and insert coiled-tubing velocity strings to enhance and maintain production. We believe that the application of fracturing and coiled-tubing technology has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP field. We recently successfully drilled and completed for the first time a horizontal multistage fracture completion in the Olmos sand at AWP. We will continue to improve and employ this new technology in South Texas and apply this to other areas in which Swift Energy operates.

In south Louisiana we also employ measurement-while-drilling techniques extensively that allow us to guide the drill bit during the drilling process. This technology allows the well bore path to be steered parallel to the salt face and to intersect multiple targeted sands in a single well bore.

Item 2. Properties

Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2008 year-end proved reserves from continuing operations of 116.4 MMBoe and production of 10.0 MMBoe by area:

Field/Area	Developed (MMBoe)	Undeveloped (MMBoe)	Total (MMBoe)	% of Reserves	% of Production	% Oil and NGLs
Lake Washington	15.5	16.4	31.8	27.3%	46.8%	91.6%
Bay de Chene	5.6	1.5	7.1	6.1%	6.2%	38.1%
Total Southeast Louisiana	21.1	17.9	38.9	33.4%	53.0%	81.9%
AWP	16.3	6.1	22.4	19.2%	14.3%	37.6%
Sun TSH	7.3	5.2	12.5	10.7%	9.4%	52.7%
Briscoe Ranch	1.5	1.0	2.5	2.1%	2.3%	53.7%
Las Tiendas	0.3	0.0	0.3	0.3%	0.6%	18.1%
Other South Texas	0.2	0.1	0.3	0.3%	1.2%	6.2%
Total South Texas	25.6	12.4	38.0	32.7%	27.8%	43.2%
Brookeland	2.1	4.1	6.2	5.3%	2.8%	63.1%
South Bearhead Creek	3.5	2.8	6.2	5.3%	5.5%	67.9%
Masters Creek	2.1	3.9	6.0	5.2%	1.7%	71.5%
Total Central Louisiana / East Texas	7.6	10.8	18.5	15.8%	10.0%	66.6%
Horseshoe Bayou /Bayou Sale	3.5	3.5	7.0	6.0%	5.0%	24.2%
Jeanerette	0.9	4.8	5.7	4.9%	0.9%	9.3%
Cote Blanche Island	0.7	4.7	5.4	4.6%	1.0%	78.1%
Bayou Penchant	0.2	0.0	0.2	0.2%	0.7%	55.8%
Total South Louisiana	5.2	13.0	18.3	15.7%	7.6%	35.6%
High Island	1.2	0.0	1.2	1.1%	0.8%	21.2%
Other	1.4	0.2	1.5	1.3%	0.8%	22.5%
Total Strategic Growth	2.6	0.2	2.7	2.4%	1.6%	21.9%
Total	62.1	54.3	116.4	100%	100%	58.2%

Focus Areas

Our operations are primarily focused in four core areas identified as Southeast Louisiana, South Louisiana, Central Louisiana/East Texas, and South Texas. In addition, we have a strategic growth area in three parishes in southwest Louisiana and another on acreage in the Four Corners area of southwest Colorado. South Texas is the oldest of our core areas, with our operations first established in the AWP field in 1989 and subsequently expanded with the acquisition of the Sun TSH, Briscoe Ranch, and Las Tiendas fields during 2007 and with additional interests in the Briscoe Ranch field in 2008. Operations in our Central Louisiana/East Texas area began in mid-1998 when we acquired the Masters Creek field in Louisiana and the Brookeland field in Texas, later adding the South Bearhead Creek field in Louisiana in late 2005. The Southeast Louisiana and South Louisiana areas were established when we acquired majority interests in producing properties in the Lake Washington field in early 2001, in the Bay de Chene and Cote Blanche Island fields in December 2004, and in the Bayou Sale, Bayou Penchant, Horseshoe Bayou, and Jeanerette fields in 2006.

Southeast Louisiana

Lake Washington. As of December 31, 2008, we owned drilling and production rights in 37,825 net acres in the Lake Washington field located in Southeast Louisiana nearshore waters within Plaquemines Parish. Since its discovery in the 1930's, the field has produced over 300 million Boe from multiple stacked Miocene sand layers radiating outward from a central salt dome and ranging in depth from 2,000 feet to 13,000 feet. The area around the dome is heavily faulted, thereby creating a large number of potential hydrocarbon traps. Approximately 92% of our proved reserves of 31.8 MMBoe in this field at December 31, 2008, consisted of oil and NGLs. Oil and natural gas from approximately 124 producing wells is gathered to four platforms located in water depths from 2 to 12 feet, with drilling and workover operations performed with rigs on barges. The fourth platform, the Westside production processing facility, was commissioned in 2008.

In 2008, we drilled and completed 23 development wells in Lake Washington. At year-end 2008, we had 119 proved undeveloped locations in this field. Our planned 2009 capital expenditures in the field will focus on recompletions of several wells.

Bay de Chene. The Bay de Chene field is located along the border of Jefferson Parish and Lafourche Parish in nearshore waters approximately 25 miles WNW of the Lake Washington field. As of December 31, 2008, Swift owned drilling and production rights in approximately 17,564 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. Partial production from the field remains shut in at this time due to damages that occurred from Hurricane Gustav in September 2008. We drilled and completed five development wells and one exploratory well in this field during 2008. The exploratory well drilled in 2008 was at our Shasta prospect located between Lake Washington and Bay de Chene. At year-end 2008, we had four proved undeveloped locations in the Bay de Chene field. During 2009, we have limited capital activity planned in Bay de Chene.

At the Shasta prospect, we plan on drilling an appraisal well in 2009 along with installing a pipeline connecting the prospect area to our Westside facility in the Lake Washington field.

South Louisiana

Cote Blanche Island. The Cote Blanche Island field, acquired in 2005, is located in nearshore waters within St. Mary Parish. As of December 31, 2008, we owned drilling and production rights in 14,699 net acres in the Cote Blanche Island field. Like Lake Washington and Bay de Chene, it produces from Miocene sands surrounding a central salt dome. During 2008 we completed one exploratory well in the Cote Blanche Island field, and at year-end 2008, we had 10 proved undeveloped locations in the field.

Bayou Sale, Horseshoe Bayou, Jeanerette, and Bayou Penchant. In October 2006 we acquired interests in four additional onshore fields in the area: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), and Bayou Penchant field in Terrebonne Parish. As of December 31, 2008, we owned drilling and production rights in a total of 24,416 net acres in these fields (5,700 in Bayou Sale, 10,512 in Horseshoe Bayou, 5,207 in Jeanerette, and 2,997 in Bayou Penchant). Bayou Sale and Horseshoe Bayou fields are adjacent to each other and located 13 miles southeast of our Cote Blanche Island field. They produce from several formations. The Jeanerette field is positioned on the flank of a large salt dome 12 miles north of Cote Blanche Island and produces form the Planulina sands. The Bayou Penchant field was discovered in the 1930s, and is located approximately 44 miles southeast of Cote Blanche Island in Terrebonne Parish. It is a non-operated field with Swift holding an average 42% working interest in these wells. The field produces from a number of Middle Miocene sands.

In 2008, we drilled and completed one development well in each of the Bayou Sale and Horseshoe Bayou fields, and we completed one out of three development wells drilled in the Jeanerette field. At year-end 2008, we had 18 proved undeveloped locations in the Bayou Sale, Horseshoe Bayou and Jeanerette fields.

Central Louisiana/East Texas

Brookeland. The Brookeland field area is located in Newton County and Jasper County, Texas, and Vernon Parish, Louisiana. As of December 31, 2008, we owned drilling and production rights in 79,063 net acres and 63,894 fee mineral acres in this field. The field consists of opposing dual lateral horizontal wells completed in the Austin Chalk formation. Oil and natural gas are produced from natural fractures encountered within the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 63% oil and natural gas liquids. At year-end 2008, we had nine proved undeveloped locations in the field. We have limited capital activity planned for this field in 2009.

Masters Creek. As of December 31, 2008, we owned drilling and production rights in 40,080 net acres and 31,200 fee mineral acres in the Masters Creek field. The Masters Creek field, located in Vernon Parish and Rapides Parish, Louisiana, consists of opposing dual lateral horizontal wells completed in the Austin Chalk formation. Oil and natural gas are produced from natural fractures encountered within the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 72% oil and NGLs. We drilled one unsuccessful development well in this field during 2008. At year-end 2008, we had nine proved undeveloped locations. We have limited capital activity planned for this field in 2009.

South Bearhead Creek. In 2005 and 2006, we acquired interests in the South Bearhead Creek field, which is located in Beauregard Parish, Louisiana approximately 50 miles south of our Masters Creek field and 30 miles north of Lake Charles, Louisiana. The field was discovered in 1958 and is a large east-west trending anticline closure with cumulative production over 4 million Boe. As of December 31, 2008, we owned drilling and production rights in 9,185 net acres in this field. Wells drilled in this field are completed in a multiple set of separate sands: Lower Wilcox - 12,500 to 14,500 fee; Middle and Upper Wilcox – 9,000 to 12,000 feet; and Cockfield – 8,000 to 9,000 feet. In 2008, we drilled and completed five development wells in this field. At year-end 2008, we had 16 proved undeveloped locations in this field. We have limited capital activity planned for this field in 2009.

South Texas

AWP. The AWP field is located in McMullen County, Texas. As of December 31, 2008 we owned drilling and production rights in 46,608 net acres in the field and were operating 565 wells producing oil and natural gas from the Olmos sand formation at depths from 9,000 to 11,500 feet. Field reserves are approximately 62% natural gas and the reservoir has provided Swift Energy an opportunity to develop extensive experience with low-permeability, tight-sand formations. We own nearly 100% of the working interests in all these operated wells. In 2008, we completed 41 out of 44 development wells drilled in the AWP field in South Texas and performed 32 fracture enhancements. At year-end 2008, we had 102 proved undeveloped locations in the field. Our planned 2009 capital expenditures will include drilling three to four wells and performing fracture enhancements for wells in this field.

Sun TSH, Briscoe Ranch, and Las Tiendas. In October 2007, Swift acquired operating interests in three additional Olmos sand reservoirs producing in the Maverick Basin. These properties are in the Sun TSH field located in La Salle County, Briscoe Ranch field located in Dimmitt County and the Las Tiendas field located in Webb County. The fields produce primarily natural gas from depths of 4,500 to 7,500 feet. As of December 31, 2008, we owned drilling and production rights in 88,652 net acres in these fields (12,552 in Sun TSH, 67,478 in Briscoe Ranch, and 8,622 in Las Tiendas). In 2008, we completed 30 of 39 development wells drilled in these fields. At year-end 2008, we were operating 257 wells in these fields and had 71 proved undeveloped locations. Our planned 2009 capital expenditures include recompleting several wells in these fields.

Strategic Growth/Other

High Island. In October 2006, we acquired interests in the High Island field in Cameron Parish along with our acquisition of interests in four fields in the South Louisiana area. The High Island field was discovered in 1983 and is located 65 miles west of Cote Blanche Island. As of December 31, 2008, we owned drilling and production rights in 2,041 net acres in this field. In 2008, we participated with a 25% working interest in one non-operated exploratory well near this field that was unsuccessful..

Four Corners. At the end of 2008, we had approximately 17,000 net acres leased in the Four Corners area of southwest Colorado.

Dispositions. In April 2006, we sold our minority interest in the natural gas processing plant and related infrastructure that serves the Brookeland and the Masters Creek fields within our Central Louisiana/East Texas area. In December 2006, we sold our interest in wells in the Garcia Ranch field within the South Texas core area.

New Zealand Areas (Discontinued Operations)

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. In June 2008, Swift Energy closed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. Accordingly, the New Zealand operations for 2007 and 2008 have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets.

Oil and Natural Gas Reserves

The following tables present information regarding proved reserves of oil and natural gas attributable to our interests in producing properties both domestically as of December 31, 2008, 2007, and 2006, and in New Zealand as of December 31, 2007 and 2006. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, has audited 97% of our 2008 domestic proved reserves and 100% of our domestic proved reserves for 2007 and 2006, and 100% of our New Zealand proved reserves for 2006. The audit by H.J. Gruy and Associates, Inc. was conducted according to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information approved by the Board of Directors of the Society of Petroleum Engineers, Inc. Based on its investigations, it is the judgment of H.J. Gruy and Associates, Inc. that Swift Energy used appropriate engineering, geologic, and evaluation principles and methods that are consistent with practices generally accepted in the petroleum industry. Reserves estimates are based on extrapolation of established performance trends, material balance calculations, volumetric calculations, analogy with the performance of comparable wells, or a combination of these methods. The classification and definitions of all proved reserves estimates are in accordance with Rule 4-10 of Regulation S-X and the auditing process as described in the Society of Petroleum Engineers document Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information.

A reserves audit and a financial audit are separate activities with unique and different processes and results. These two activities should not be confused. As currently defined by the Society of Petroleum Engineers, a reserves audit should be of sufficient rigor to determine the appropriate reserve classification for all reserves in the property set evaluated and to clearly state the reserves classification system being utilized. A financial audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

Estimates of future net revenues from our proved reserves and their PV-10 Value are made using oil and natural gas sales prices in effect as of the dates of such estimates excluding the effects of hedging and are held constant, for that year's reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of natural gas contracts, the use of fixed and determinable contractual price escalations. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables. As of December 31, 2008, we did not have any derivative instruments covering future production affecting these calculations. The weighted averages of such year-end 2008 prices domestically were $4.96 per Mcf of natural gas, $44.09 per barrel of oil, and $25.39 per barrel of NGL, compared to $6.65, $93.24, and $56.28 at year-end 2007 and $5.84, $60.07, and $31.54 at year-end 2006, respectively. At December 31, 2008, we did not have any reserves in New Zealand. The weighted averages of such year-end 2007 prices for New Zealand were $3.08 per Mcf of natural gas, $93.20 per barrel of oil, and $36.98 per barrel of NGL, compared to $3.59, $63.51, and $26.84 in 2006, respectively. The weighted averages of such year-end 2007 prices for all our reserves, both domestically and in New Zealand, were $6.19 per Mcf of natural gas, $93.24 per barrel of oil, and $54.63 per barrel of NGL, compared to $5.46, $60.41, and $30.93 in 2006, respectively.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the SEC and their PV-10 Value as of December 31, 2008, 2007, and 2006. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. We combine NGL volumes with oil volumes solely for reserves volumes reporting purposes. We apply oil prices to proved oil reserves volumes and apply NGL prices to proved NGL reserves volumes in determining both the PV-10 and standardized measure values. PV-10 is a non-GAAP measure; see the reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure, in the section below this table.

	As of December 31, 2008		
	Total	Domestic	Discontinued Operations
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	172,214	172,214	---
Proved undeveloped	120,166	120,166	---
Total	292,380	292,380	---
Oil reserves (MBbl):			
Proved developed	33,411	33,411	---
Proved undeveloped	34,299	34,299	---
Total	67,710	67,710	---
Total Estimated Reserves (MBoe)	116,440	116,440	---
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 880	$ 880	$ ---
Proved undeveloped	481	481	---
PV-10 Value	$ 1,361	$ 1,361	$ ---

	As of December 31, 2007		
	Total	Domestic	Discontinued Operations
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	187,152	172,974	14,178
Proved undeveloped	206,862	170,824	36,038
Total	394,014	343,798	50,216
Oil reserves (MBbl):			
Proved developed	36,753	35,548	1,205
Proved undeveloped	47,702	40,934	6,768
Total	84,455	76,482	7,973
Total Estimated Reserves (MBoe)	150,124	133,781	16,343
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 2,071	$ 1,999	$ 73
Proved undeveloped	1,823	1,790	32
PV-10 Value	$ 3,894	$ 3,789	$ 105

	As of December 31, 2006		
	Total	Domestic	Discontinued

			Operations
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	151,276	133,815	17,462
Proved undeveloped	172,855	135,846	37,009
Total	324,131	269,661	54,471
Oil reserves (MBbl):			
Proved developed	34,956	33,346	1,611
Proved undeveloped	47,163	40,119	7,044
Total	82,119	73,465	8,655
Total Estimated Reserves (MBoe)	136,141	118,408	17,733
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 1,382	$ 1,307	$ 75
Proved undeveloped	1,326	1,137	189
PV-10 Value	$ 2,708	$ 2,444	$ 264

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 natural 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 natural 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 natural 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 natural gas reserves.

The closest GAAP measure to PV-10, a non-GAAP measure, is the standardized measure of discounted future net cash flows. We believe PV-10 is a helpful measure in evaluating the value of our oil and natural gas reserves and many securities analysts and investors use PV-10. We use PV-10 in our ceiling test computations, and we also compare PV-10 against our debt balances. The following table is a reconciliation between PV-10 and the standardized measure of discounted future net cash flows:

	As of December 31, 2008		
	Total	Domestic	Discontinued Operations
(in millions)			
PV-10 Value	$ 1,361	$ 1,361	$ ---
Future income taxes (discounted at 10%)	(280)	(280)	---
Asset retirement obligations (discounted at 10%)	(48)	(48)	---
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,033	$ 1,033	$ ---

	As of December 31, 2007		
	Total	Domestic	Discontinued Operations
(in millions)			
PV-10 Value	$ 3,894	$ 3,789	$ 105
Future income taxes (discounted at 10%)	(1,212)	(1,211)	(1)
Asset retirement obligations (discounted at 10%)	(46)	(38)	(8)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 2,636	$ 2,540	$ 96

	As of December 31, 2006		
	Total	Domestic	Discontinued Operations
(in millions)			

PV-10 Value	$ 2,708	$ 2,444	$ 264
Future income taxes (discounted at 10%)	(800)	(778)	(22)
Asset retirement obligations (discounted at 10%)	(39)	(34)	(5)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,869	$ 1,632	$ 237

Domestic Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our domestic proved undeveloped reserves as of December 31, 2008:

Year Added	Volume (MMBoe)	% of PUD Volumes	PV-10 Value (in millions)	% of PUD PV-10 Value
2008	7.9	15%	$ 62.1	13%
2007	12.9	24%	90.1	19%
2006	6.6	12%	79.4	17%
2005	8.1	15%	79.3	16%
2004	6.1	11%	88.8	18%
Prior to 2004	12.7	23%	81.8	17%
Total	54.3	100%	$ 481.5	100%

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2008, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 116.4 MMBoe by approximately 0.1 MMBoe, and increase the domestic PV-10 Value of $1.4 billion by approximately $64 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.2 MMBoe and decrease the domestic PV-10 Value by approximately $64 million.

As of December 31, 2008 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.2 MMBoe and increase the domestic PV-10 Value by approximately $38 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.3 MMBoe and decrease the domestic PV-10 Value by approximately $37 million.

Oil and Gas Wells

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

	Oil Wells	Gas Wells	Total Wells(1)(2)
December 31, 2008:			
Gross	510	817	1,327
Net	447.4	744.9	1,192.3
December 31, 2007:			
Gross	504	761	1,265
Net	437.4	719.9	1,157.3
December 31, 2006:			
Gross	423	662	1,085
Net	353.4	562.4	915.8

(1) Excludes 65 service wells in 2008 and 2007, and 51 service wells in 2006.
(2) Includes 49 wells in New Zealand in both 2007 and 2006.

13

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2008:

	Developed(1)		Undeveloped(2)	
	Gross	Net	Gross	Net
Alabama	8,120	1,580	176	1
Alaska	---	---	40,634	13,737
Colorado	---	---	26,694	16,933
Louisiana	126,702	108,125	54,853	48,987
Texas	150,651	111,613	98,610	92,630
Wyoming	640	151	6,651	4,664
Offshore Louisiana	4,609	277	---	---
All other states	---	---	721	257
Total	290,722	221,746	228,339	177,209

(1) Fee mineral acres in the Brookeland and Masters Creek fields are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 68,689 undeveloped fee mineral acres for a total of 95,034 fee mineral acres.

(2) We also have 32,010 additional undeveloped acres in Texas and Wyoming in which we maintain an overriding royalty interest ("ORRI") ranging between 1% and 7.5%.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2008:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2008	Exploratory — Domestic	3	2	1	1.8	1.5	0.3
	Development — Domestic	123	108	15	120.0	106.0	14.0
	Exploratory — New Zealand	—	—	—	—	—	—
	Development — New Zealand	—	—	—	—	—	—
2007	Exploratory — Domestic	5	2	3	5.0	2.0	3.0
	Development — Domestic	64	59	5	62.6	58.1	4.5
	Exploratory — New Zealand	—	—	—	—	—	—
	Development — New Zealand	—	—	—	—	—	—
2006		6	—	6	5.5	—	5.5

Exploratory — Domestic						
Development — Domestic	49	42	7	47.6	40.6	7.0
Exploratory — New Zealand	4	—	4	4.0	—	4.0
Development — New Zealand	4	3	1	4.0	3.0	1.0

Operations

We generally seek to be the operator of 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 this 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 natural gas properties.

Oil and natural gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator's direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2008 totaled $15.8 million and ranged from $500 to $2,687 per well per month.

Marketing of Production

We typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We usually sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. In 2008 and 2007, several companies accounted for 10% or more of our total revenues. Shell Oil Company and its affiliates accounted for approximately 29% and 42% of our total oil and gas sales in 2008 and 2007, respectively. In 2008 and 2007, Chevron and its domestic affiliates accounted for 25% and 22% of our total oil and gas sales, respectively. However, due to the demand for oil and natural gas and availability of other purchasers, we do not believe that the loss of any single oil or natural gas purchaser or contract would materially affect our revenues.

Our oil production from the Lake Washington field is delivered into ExxonMobil's crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices or at fixed prices tied to the then current NYMEX crude oil contract for the applicable month(s). Our natural gas production from this field 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. Natural gas delivered into Tennessee Gas Pipeline is processed at the Yscloskey plant. In 2008, we completed a connection which provides for the delivery of natural gas from this field to El Paso's Southern Natural Gas pipeline system (Sonat) and the processing of gas delivered to Sonat at the Toca Plant.

In 2008, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP field with Enterprise Hydrocarbons L.P. and Enterprise South Texas Pipeline, replacing the ten-year agreements with Enterprise that expired in 2008.

In the Sun TSH, Briscoe Ranch and Las Tiendas fields, our oil production is sold at prevailing market prices and transported to market by truck. Natural gas from the fields is delivered either to Enterprise South Texas Gathering or Regency Gas Services. For natural gas delivered to Enterprise, the natural gas is sold to Enterprise; with Swift receiving revenues from residue gas sales and processed liquids. For natural gas delivered to Regency, the natural gas production is transported to a downstream processing plant. We sell the residue gas at prevailing market prices and receive processing revenues from Regency.

Our oil production from the Brookeland, Masters Creek and South Bearhead Creek fields is sold to various purchasers at prevailing market prices. Our natural gas production from the Brookeland and Masters Creek fields is processed under long term gas processing contracts with Eagle Rock Operating, LLC. The processed liquids and residue gas production are sold in the spot market at prevailing prices. South Bearhead Creek natural gas production is sold into the interstate market on Trunkline Gas Company's pipeline at prevailing market prices.

Our oil production from the Bay de Chene and Cote Blanche Island fields is transported on barges for sales to various purchasers at prevailing market prices. Natural gas production from both fields is sold into intrastate pipelines with prices tied to monthly and daily natural gas price indices.

In the fields of Bayou Sale, Horseshoe Bayou, High Island and Jeanerette in South Louisiana, we market our own production and sell the oil production to various purchasers at prevailing market prices. Bayou Sale and Horseshoe Bayou oil production is delivered into Plains All-American pipeline. Oil production from High Island and Jeanerette fields is transported to market by truck. Natural gas production for each of these fields is sold into one or more interstate pipelines at prevailing market prices.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and natural gas production from our continuing operations for the three-year period ended December 31, 2008:

	Year Ended December 31,		
	2008	2007	2006
Net Sales Volume:			
Oil (MBbls)	5,420	7,045	6,721
Natural Gas Liquids (MBbls)	1,211	774	460
Natural gas (MMcf)	20,503	16,782	13,604
Total (MBoe)	10,049	10,617	9,449
Average Sales Price:			
Oil (Per Bbl)	$101.38	$71.92	$64.28
Natural Gas Liquids (Per Bbl)	$57.15	$49.72	$38.70
Natural gas (Per Mcf)	$8.54	$6.42	$6.44
Average Production Cost (Per Boe)	$18.44	$13.63	$11.77

Oil and natural gas prices declined significantly in the latter part of 2008 from levels earlier in the year, and the average sales prices for 2008 are not indicative of prices in effect at the end of 2008. The prices above also do not include the effects of hedging. Quarterly prices and hedge adjusted pricing are detailed in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations” section of this Form 10-K.

Our New Zealand production and pricing information is included in the Discontinued Operations discussion within the Management’s Discussion and Analysis of Financial Condition and Results of Operations section of this Form 10-K.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or individual injuries. The oil and natural gas exploration business is also subject to environmental hazards, such as oil spills, natural 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. See “1A. Risk Factors” of this report for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance, officer and director liability insurance, and property damage insurance. Prior to and at the time of Hurricanes Katrina and Rita, we maintained business interruption insurance as well. Since such time, the cost of such business interruption insurance coverage increased to a level that we believe makes it uneconomical to maintain at this time. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and participating collars when appropriate. At December 31, 2008, we did not have any price floors in place.

Competition

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and natural 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 natural 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. Our ability to replace and expand our reserves base depends on our continued ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling and acquisition.

Regulations

Environmental Regulations

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, and other ecologically sensitive and protected areas, and impose substantial remedial liabilities for pollution resulting from drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of significant investigatory or remedial obligations, and the imposition of injunctive relief that limits or prohibits our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current environmental laws and regulations and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

We currently own or lease, and have in the past owned or leased, numerous properties in connection with our operations that have been used for the exploration and production of oil and natural gas for many years. Although we have used operation and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as “CERCLA” or the “Superfund” law, the federal Resource Conservation and Recovery Act or “RCRA,” the federal Clean Water Act, the federal Clean Air Act, the federal Oil Pollution Act or “OPA,” and analogous state laws. Under such laws and any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment.

Our operations offshore in the Gulf of Mexico are subject to OPA, which imposes a variety of requirements related to the prevention of oil spills, and liability for damages resulting from such spills in United States waters. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party fails to report the spill or cooperate fully in any resulting cleanup. The OPA also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe our operations are in substantial compliance with OPA requirements.

United States Federal and State Regulation of Oil and Natural Gas

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

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

Since December 2007, Congress has passed the Energy Independence and Security Act of 2007, the Energy Economic Stabilization Act of 2008, and the American Recovery and Reinvestment Act of 2009, each of which contains various provisions affecting the oil and gas industry and related tax provisions. In future periods, Congress may decide to revisit legislation introduced in prior sessions to repeal existing incentives or impose new taxes on the exploration and production of oil and natural gas, and/or create new incentives for alternative energy sources. If enacted, such legislation could reduce the demand for and uses of oil, natural gas and other minerals and/or increase the costs incurred by the Company in its exploration and production activities, which could affect the Company's revenues, costs, and profits.

Production of any oil and natural gas by us will be affected to some degree by state regulations. Many states in which we operate have statutory provisions regulating the production and sale of oil and natural gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and natural gas and to protect correlative rights to produce oil and natural gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and natural gas produced by assigning allowable rates of production to each well or proration unit, which could restrict the rate of production below the rate that a well would otherwise produce in the absence of such regulation. In addition, certain state regulatory authorities can limit the number of wells or the locations where wells may be drilled. Any of these actions could negatively affect the amount or timing of revenues.

Federal Leases

Some of our properties are located on federal oil and natural 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.

Litigation

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 natural gas wells. In our opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations. We have further discussed our New Zealand litigation in footnote 8 of the Notes to Consolidated Financial Statements ("Discontinued Operations").

Employees

At December 31, 2008, we employed 334 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2008, we occupied approximately 126,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten-year lease expiring February 2015. The lease requires payments of approximately $260,000 per month. In October 2008, we executed a new lease agreement, effective August 1, 2009, for approximately 76,000 additional square feet in the same office space as our lease mentioned above. This lease expires February 2015 and requires payments of approximately $174,000 per month. We also have field offices in various locations from which our employees supervise local oil and natural gas operations.

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.

Item 1A. Risk Factors

The nature of the business activities conducted by Swift Energy subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in Items 1 and 2 Business and Properties "Competition" and "Regulations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

The global recession could have a material adverse impact on our financial results.

The United States and other world economies are in a recession which could last well beyond 2009. The recession has led to less demand and lower pricing for crude oil and natural gas, as demonstrated by the decline in commodity prices which occurred during the later part of 2008 and into 2009. Our profitability will be significantly affected by decreased demand and lower commodity prices. Our future access to capital and the availability of future financing could be limited due to tightening credit markets that could affect our ability to fund our capital projects.

The current credit crisis may negatively affect our access to capital, our liquidity, and ability to refinance our debt.

Our future access to capital could be limited due to tightening credit markets, which could affect our liquidity and as a result, our ability to fund our capital projects. The continued credit crisis and related turmoil in the global financial system is likely to continue to materially affect our liquidity and our business and financial condition.

The global credit crisis and recession may inhibit our lenders from fully funding our line of credit or cause them to make the terms of our line of credit costlier or more restrictive. We are subject to semi-annual reviews of our borrowing base and commitment amount under our line of credit, and do not know the result of the upcoming redetermination or the effect of then current oil and gas prices on that process. Additionally, both our line of credit and our $150 million of Senior Notes due 2011 mature in the same year, and although over two years away, long-term restriction or freezing of the capital markets may affect the availability or pricing of our renewal or replacement of those debt obligations.

The current state of the financial and credit markets may affect our insurers, oil and gas purchasers, suppliers and commodity derivatives counterparties.

Continuation or worsening of the current state of the financial and credit markets may negatively affect the ability of various purchasers, suppliers, insurers, and commodity derivative counterparties to perform under the terms of contracts or financial arrangements we have with them. Although we have heightened our level of scrutiny of our contractual counterparties, our assessment of the risk of non-performance by various parties is subject to sudden swings in the financial and credit markets. This same crisis may adversely impact insurers and their ability to pay current and future insurance claims that we may have.

The current credit crisis may negatively affect our access to capital and ability to refinance our debt.

Our future access to capital could be limited due to tightening credit markets that could affect our ability to fund our capital projects The global credit crisis and recession may inhibit our lenders from fully funding our line of credit or cause them to make the terms of our line of credit costlier or more restrictive. We are subject to semi-annual reviews of our borrowing base and commitment amount under our line of credit, and do not know the result of the upcoming redetermination or the effect of then current oil and gas prices on that process. Additionally, both our line of credit and our $150 million of Senior Notes due 2011 mature in the same year, and although over two years away, long-term restriction or freezing of the capital markets may affect the availability or pricing of our renewal or replacement of those debt obligations.

Approximately 49% of our 2008 reserves and 61% of our 2008 production are located in our South Louisiana and Southeast Louisiana core areas. If this area is hit by a hurricane or we have a pipeline outage, it could cause us to suffer significant losses.

Increased hurricane activity over the past three years has resulted in production curtailments and physical damage to our Gulf Coast operations. For example, a significant percentage of our production was shut down by Hurricanes Katrina and Rita in 2005, and by Hurricanes Gustav and Ike in 2008. Due to increased costs after the 2005 hurricanes, we no longer carry business interruption insurance. If hurricanes damage the Gulf Coast region where we have a significant percentage of our operations, our cash flow would suffer. This decrease in cash flow, depending on the extent of the decrease, could reduce the funds we would have available for capital expenditures and reduce our ability to borrow money or raise additional capital.

We have incurred a write-down of the carrying values of our properties in the current year and could incur additional write-downs in the future.

Under the full cost method of accounting, SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and natural gas properties for possible write-down or impairment. Under these rules, capitalized costs of proved reserves may not exceed a ceiling calculated as the present value of estimated future net revenues from those proved reserves, determined using a 10% per year discount and unescalated prices in effect as of the end of each fiscal quarter. Capital costs in excess of the ceiling must be permanently written down. Low oil and gas prices at year-end 2008 which have led to a $473.1 million non-cash after-tax write-down of our oil and gas properties have continued to fall in the beginning months of 2009. If these prices persist, subject to the degree to which we incur additional capital costs on oil and gas properties and add proved reserves, we may be required to record further write-downs of our oil and gas properties at the end of the first quarter of 2009 or in subsequent 2009 periods.

Our oil and natural gas exploration and production business involves high risks and we may suffer uninsured losses.

These risks include blowouts, explosions, adverse weather effects and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, such as business interruption, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices would adversely affect our financial results.

Our future revenues, net income, cash flow, and the value of our oil and natural gas properties depend primarily upon market prices for oil and natural gas. Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. The recent record high oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, currency exchange rates, and political conditions in major oil producing regions, especially the Middle East. A significant decrease in price levels for an extended period would negatively affect us in several ways:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to increase production or replace reserves;

-

certain reserves would no longer be economic to produce, leading to both lower cash flow and proved reserves;

- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserves values, reducing our liquidity and possibly requiring mandatory loan repayments; and

- access to other sources of capital, such as equity or long term debt markets, could be severely limited or unavailable in a low price environment.

Consequently, our revenues and profitability would suffer.

Our level of debt could reduce our financial flexibility.

As of December 31, 2008, our total debt comprised approximately 49% of our total capitalization. Although our bank credit facility and indentures limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness, we will be permitted to incur significant additional indebtedness, including secured indebtedness, in the future if specified conditions are satisfied. Higher levels of indebtedness could negatively affect us by requiring us to dedicate a substantial portion of our cash flow to the payment of interest, and limiting our ability to obtain financing or raise equity capital in the future.

Estimates of proved reserves are uncertain, and revenues from production may vary significantly from expectations.

The quantities and values of our proved reserves included in this report are only estimates and subject to numerous uncertainties. Estimates by other engineers might differ materially. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation. These estimates depend on assumptions regarding quantities and production rates of recoverable oil and natural gas reserves, future prices for oil and natural gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant.

Any significant variance from the assumptions used could result in the actual amounts of oil and natural gas ultimately recovered and future net cash flows being materially different from the estimates in our reserves reports. In addition, results of drilling, testing, production, and changes in prices after the date of the estimates of our reserves may result in substantial downward revisions. These estimates may not accurately predict the present value of net cash flows from our oil and natural gas reserves.

At December 31, 2008, approximately 47% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

If we cannot replace our reserves, our revenues and financial condition will suffer.

Unless we successfully replace our reserves, our long-term production will decline, which could result in lower revenues and cash flow. When oil and natural gas prices decrease, our cash flow decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank credit facility. Even if we have the capital to drill, unsuccessful wells can hurt our efforts to replace reserves. Additionally, lower oil and natural gas prices can have the effect of lowering our reserves estimates and the number of economically viable prospects that we have to drill.

Drilling wells is speculative and capital intensive.

Developing and exploring properties for oil and natural gas requires significant capital expenditures and involves a high degree of financial risk, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The budgeted costs of drilling, completing, and operating wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an oil or natural gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- hurricanes or tropical storms;
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented, as is the case in our declining business interruption insurance following the hurricanes in 2005. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our financial condition.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Reserves on acquired properties may not meet our expectations, and we may be unable to identify liabilities associated with acquired properties or obtain protection from sellers against associated liabilities.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property’s production and profitability. In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and natural gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Louisiana and Texas, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

In addition, our assessment of acquired properties may not reveal all existing or potential problems or liabilities, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the properties may not perform in accordance with our expectations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities, if at all, to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects. In addition, a variety of factors, including geological and market-related, can cause a well to become uneconomical or only marginally economical. For example, if oil and natural gas prices are much lower after we complete a well than when we identified it as a prospect, the completed well may not yield commercially viable quantities.

In many instances, title opinions on our oil and gas acreage are not obtained if in our judgment it would be uneconomical or impractical to do so.

As is customary in the industry, we generally acquire oil and natural 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.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and expose us to risk of financial loss.

We enter into hedging transactions for our oil and natural gas production to reduce exposure to fluctuations in the price of oil and natural gas, primarily to protect against declines in prices, although we typically enter into only short-term hedges covering less than 50% of our anticipated production, which limits the price protection they provide. We did not have any derivative instruments covering future production at year-end 2008. Our hedging transactions have also historically consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors. We intend to continue to enter into these types of hedging transactions in the foreseeable future when appropriate. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions other than floors may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Additionally, hedging transactions other than floors may expose us to cash margin requirements.

We may have difficulty competing for oil and gas properties or supplies.

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and natural gas properties, as well as for the 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 natural 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.

Our business depends on oil and natural gas transportation facilities, some of which are owned by others.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Governmental laws and regulations are costly and stringent, especially those relating to environmental protection.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in our efforts to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operations. Changes in or additions to environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could have a material adverse effect on our operations and financial position.

Item 1B. Unresolved Staff Comments

None.

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. 1

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

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

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

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

Exploratory Well — A well drilled either in search of a new, as yet undiscovered, oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir. 2

FASB — The Financial Accounting Standards Board.

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.

MBoe — Thousand barrels of oil equivalent.

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.

MMBoe — Million barrels of oil equivalent.

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

MMcf — Million cubic feet of natural gas.

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

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

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

NGL— Natural gas liquid.

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

Proved Developed Oil and Gas Reserves — Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. 3

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. 4

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. 5

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

PV-10 Value — The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization. PV-10 Value is a non-GAAP measure and its use is explained under “Item 2. Properties - Oil and Natural Gas Reserves” above in this Form 10-K.

SFAS — Statement of Financial Accounting Standards.

Notes to Abbreviations and Terms Above

1. This is only an abbreviated definition. Please refer to Securities and Exchange Commission’s definition of this term at Rule 4-10(a)(11) of Regulation S-X.
2. This is only an abbreviated definition. Please refer to Securities and Exchange Commission’s definition of this term at Rule 4-10(a)(10) of Regulation S-X.

3. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(3) of Regulation S-X.
4. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(2) of Regulation S-X.
5. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(4) of Regulation S-X.

Item 3. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation and claims incidental to our business. We have further discussed our New Zealand litigation in footnote 8 of the Notes to Consolidated Financial Statements ("Discontinued Operations")

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

No matters were submitted during the fourth quarter of 2008 to a vote of security holders.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock, 2007 and 2008

Our common stock is traded on the New York Stock Exchange under the symbol "SFY." The high and low quarterly closing sales prices for the common stock for 2007 and 2008 were as follows:

	2007				2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$ 37.37	$ 39.09	$ 35.98	$ 39.89	$ 39.64	$ 44.80	$ 36.83	$ 15.30
High	$ 44.91	$ 45.78	$ 47.31	$ 47.72	$ 49.98	$ 66.06	$ 67.03	$ 37.83

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 218 stockholders of record as of December 31, 2008.

Share Performance Graph

The following Share Performance Graph shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

28

Item 6. Selected Financial Data

(in thousands except per share and well amounts)	2008	2007	2006	2005	2004
Total Revenues from Continuing Operations (1)	$ 820,815	$ 654,121	$ 550,836	$ 354,365	$ 257,313
Income (Loss) from Continuing Operations, Before Income Taxes and Change in Accounting Principle (1)	$ (412,758)	$ 244,556	$ 248,308	$ 156,129	$ 86,083
Income (Loss) from Continuing Operations (1)	$ (257,130)	$ 152,588	$ 151,074	$ 97,880	$ 54,340
Net Cash Provided by Operating Activities - Continuing Operations	$ 582,027	$ 442,282	$ 383,241	$ 236,791	$ 147,114
Per Share and Share Data					
Weighted Average Shares Outstanding(1)	30,661	29,984	29,265	28,496	27,822
Earnings per Share--Basic(1)	$ (8.39)	$ 5.09	$ 5.16	$ 3.43	$ 1.95
Earnings per Share--Diluted(1)	$ (8.39)	$ 4.98	$ 5.03	$ 3.34	$ 1.92
Shares Outstanding at Year-End	30,869	30,179	29,743	29,010	28,090
Book Value per Share at Year-End	$ 19.47	$ 27.70	$ 26.83	$ 20.94	$ 16.88
Market Price					
High	$ 67.03	$ 47.72	$ 51.84	$ 50.01	$ 30.34
Low	$ 15.30	$ 35.98	$ 35.48	$ 24.77	$ 15.90
Year-End Close	$ 16.81	$ 44.03	$ 44.81	$ 45.07	$ 28.94
Assets					
Current Assets	$ 78,086	$ 199,950	$ 83,783	$ 110,199	$ 51,694
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$ 1,431,447	$ 1,760,195	$ 1,239,722	$ 862,717	$ 731,868
Total Assets	$ 1,517,288	$ 1,969,051	$ 1,585,682	$ 1,204,413	$ 990,573

Liabilities					
Current Liabilities	$ 153,499	$ 210,161	$ 145,471	$ 98,421	$ 68,618
Long-Term Debt	$ 580,700	$ 587,000	$ 381,400	$ 350,000	$ 357,500
Total Liabilities	$ 916,411	$ 1,132,997	$ 787,765	$ 597,094	$ 516,401
Stockholders' Equity	$ 600,877	$ 836,054	$ 797,917	$ 607,318	$ 474,172
Number of Domestic Employees	334	298	272	236	203
Domestic Producing Wells					
Swift Operated	1,168	1,091	926	854	798
Outside Operated	159	127	112	69	97
Total Domestic Producing Wells	1,327	1,218	1,038	923	895
Domestic Wells Drilled (Gross)	126	69	55	54	54
Domestic Proved Reserves					
Natural Gas (Bcf)	292.4	343.8	269.7	225.3	237.9
Oil, NGL, & Condensate (MMBbls)	67.7	76.5	73.5	69.8	69.1
Total Domestic Proved Reserves (MMBoe equivalent)	116.4	133.8	118.4	107.3	108.8
Domestic Production (MMBoe equivalent)	10.0	10.6	9.4	7.2	7.0
Domestic Average Sales Price (2)					
Natural Gas (per Mcf)	$ 8.54	$ 6.42	$ 6.44	$ 7.40	$ 5.74
Natural Gas Liquids (per barrel)	$ 57.15	$ 49.72	$ 38.70	$ 34.00	$ 24.84
Oil (per barrel)	$ 101.38	$ 71.92	$ 64.28	$ 53.45	$ 40.04
Boe Equivalent	$ 79.00	$ 61.49	$ 56,89	$ 49.61	$ 36.90

1 Amounts have been retroactively adjusted in all periods presented to give recognition to: (a) discontinued operations related to the sale of our New Zealand oil & gas assets, and (b) the conversion of production and reserves volumes to a Boe basis.

2 These prices do not include the effects of our hedging activities which were recorded in "Price-risk management and other, net" on the accompanying statements of income. The hedge adjusted prices are detailed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this Form 10-K.

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

You should read the following discussion and analysis in conjunction with our financial information and our audited consolidated financial statements and accompanying notes for the years ended December 31, 2008, 2007, and 2006 included with this report. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 42 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from the inland waters of Louisiana and from our onshore Louisiana and Texas properties.

We are the largest producer of crude oil in the state of Louisiana, and due to increasing emphasis on our South Louisiana operations, we have become predominantly an oil producer, with oil constituting 54% of our 2008 domestic production, and oil and natural gas liquids ("NGLs") together making up 66% of our 2008 domestic production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in 2008.

Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our discontinued New Zealand operations.

Actions taken in response to the credit crisis and downturn in the industry

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling prices for oil and natural gas, all of which began late in the third quarter of 2008, will have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. Oil and natural gas prices continued to decline during the fourth quarter of 2008, leading to a 49% decline in average prices per BOE received when compared to average prices received in the third quarter of 2008. These declines reduced our cash flow from operations in the fourth quarter and given further price declines in early 2009, will continue to reduce our cash flow from operations in future periods in which prices remain at these lower levels.

The company has taken several steps to manage the decline in expected cash flow in 2009 and provide liquidity in future periods including:

- Reduced 2009 budgeted capital expenditures. We have reduced our 2009 capital expenditures budget to a range of $125 million to $150 million, which we expect to be in line with our expected cash flows from operating activities for 2009.
- Released all drilling rigs in early 2009. As we have limited drilling activities in our reduced 2009 capital expenditures budget we will begin drilling again as drilling costs decrease and become more in line with the current oil and gas pricing environment.
- Reduced our workforce. In early 2009, we reduced our headcount to lower general and administrative costs in future periods, although the first quarter of 2009 effect will be minimal given severance and other associated costs.
- Adjusted operations. We have adjusted our operations and facility usage to levels which will reduce lease operating expense in 2009 and future periods.
- Reviewed the credit worthiness of customers. Given the downturn in the industry we have examined every one of our purchasers of oil and gas for credit worthiness and 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. We also obtain letters of

credit or parent company guaranties from certain customers, if applicable, to reduce risk of loss.

- Reviewed the banks in our line of credit facility. In light of recent credit market volatility, many financial institutions have experienced liquidity issues, and governments have intervened in these markets to create liquidity, and provide capital. We have reviewed the credit worthiness of the banks that fund our credit facility and thus far the liquidity of our banks has not been impacted.
- Monitored our debt covenants. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of these agreements and expect to remain in compliance with these provisions in 2009 and future periods.

Financial Condition

In the fourth quarter of 2008, as a result of lower oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and natural gas properties.

Our debt to capitalization ratio increased to 49% at December 31, 2008, as compared to 41% at year-end 2007, as total equity and retained earnings decreased as a result of the year-end 2008 non-cash write-down of our oil and gas properties. Our debt to PV-10 ratio increased to 43% at December 31, 2008 from 15% at year-end 2007, primarily due to lower period-end prices used in the reserves calculation.

Operating Results

In our 2008 continuing operations we had record cash flow, with cash flows from operating activities from continuing operations increasing 32% over 2007 amounts to $582.0 million.

We also had record revenues of $820.8 million for 2008, an increase of 25% over comparable 2007 levels. Our weighted average sales price received increased 28% to $79.00 per Boe for 2008 from $61.49 in 2007. Our $166.7 million, or 25%, increase in revenues resulted from higher oil and gas prices during 2008, offset slightly by the decrease in production.

Income (Loss) from continuing operations decreased to a loss of $257.1 million compared to 2007 amounts.

Production decreased 5% to 10.0 MMBoe as a result of production shut-ins necessitated by Hurricanes Gustav and then Ike. Additionally, the effects of the hurricanes were felt through the third and fourth quarters as the drilling and completion of several wells were delayed as we moved drilling rigs into safe harbor before the hurricanes and then returned them to the field afterwards. Hurricane Gustav shut-down procedures were implemented in the third quarter in our Lake Washington field and South Louisiana core area, with some damage, while Bay de Chene field experienced significant damage to its production facilities, and some production equipment in the field was damaged or destroyed. Hurricane Ike in mid-September caused damage to several fields in our South Louisiana core area and our High Island field due to high water levels. As a result of these hurricanes, approximately 0.5 MMBoe of production was shut-in during the third quarter of 2008, and approximately 0.3 MMBoe of production was shut-in for the fourth quarter of 2008. By October 1, 2008, production in our Lake Washington field had returned to 85% of pre-storm levels and all operated production had been restored in our South Louisiana core area. We anticipate production in our Bay de Chene field to be below previous levels until mid-year 2009. We anticipate our total cost for the replacement of assets, repairs, and clean-up costs related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will approximate $25 million and we believe a portion of this will be reimbursed by insurance coverage. During 2008, we incurred approximately $15 million of these costs, both capital and lease operating, and expect the remainder of these costs will be incurred in the first two quarters of 2009 and mainly relate to capital projects.

Our overall costs and expenses increased in 2008 by $824.0 million, primarily due to the non-cash write-down of oil and gas properties. The largest increase in these costs and expenses was attributable to the non-cash write-down of oil and gas properties of $754.3 million. Lease operating costs increased by 48% due to a higher well count mainly from our South Texas property acquisition in late 2007, increasing costs for industry goods and services, higher natural gas processing costs during the year, and clean-up and repair activities related to Hurricanes Gustav and Ike. Depreciation, depletion and amortization expense increased 18%, mainly due to our larger depletable property base and a reduction in reserves volumes. Severance and other taxes also increased 9% mainly due to increased oil and gas revenues. We expect the market forces that were putting upward pressure on production costs in early 2008 will continue to soften as activity levels decline in response to falling commodity prices and current conditions in the financial markets in 2009. In 2009, we will continue to focus upon our capital efficiency to better manage our costs and expenses, a difficult task in the inflationary cost environment prevalent in the industry over the last several years.

Our Lake Washington field has experienced natural declines and reservoir pressure issues for some time. In 2008, permits were submitted to the State of Louisiana to provide additional water injection into the Newport reservoir for pressure maintenance. However, based on our recent experiences, we do not anticipate that pressure maintenance activities will increase our production in Lake Washington before late in 2009 or early 2010. Water injection into the current injection well is averaging about 1,200-1,300 barrels per day.

We have spent considerable time and capital on facility capacity upgrades and additions in the Lake Washington field. Our fourth production platform, the Westside facility, was commissioned in the second quarter of 2008 and has increased our crude oil processing capacity another 10,000 barrels per day.

We ended 2008 with domestic proved reserves of 116.4 MMBoe, a decrease of 13% over year-end 2007 domestic reserves of 133.8 MMBoe. As a result of performance, drilling, new geophysical information and revised mapping of multiple zones and the salt interface, a downward technical adjustment occurred in the Cote Blanche Island field. Our St. Mary Land #82 proved undeveloped location was drilled during 2008. Although successfully completed in one horizon, several other horizons were found to be non-commercial. These results led to downward technical adjustments of reserves in this area. Downward adjustments due to lower pricing at year-end than in prior periods also led to lower reserves at the end of 2008. Our year-end 2008 domestic proved reserves were 43% crude oil, 42% natural gas, and 15% NGLs, compared to 44% crude oil, 43% natural gas, and 13% NGLs a year earlier. Domestic proved reserves were 53% proved developed at December 31, 2008. Our 2008 domestic production was 54% crude oil, down from 66% in 2007.

Asset Acquisitions and Dispositions

In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the property sale, and have deferred the potential gain on this permit sale pending the outcome of this litigation. Accordingly, our New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets.

In September 2008, we acquired oil and natural gas interests in South Texas for approximately $45.9 million in cash including purchase price adjustments. The property interests are located in the Briscoe "A" lease in Dimmit County. These properties are now included within our South Texas core area.

Capital Expenditures

Our capital expenditures related to continuing operations during 2008 were $674.8 million, which includes $46.5 million in acquisitions. This amount increased by $24.2 million as compared to 2007, primarily due to an increase in our spending on drilling and development, predominantly in our Southeast Louisiana and South Texas core areas. These expenditures were funded by $582.0 million of cash provided by operating activities from continuing operations and proceeds from our New Zealand asset sale.

Given the current low oil and gas pricing environment, our presently budgeted 2009 capital expenditures range between $125 million to $150 million, net of minor non-core dispositions and excluding any property acquisitions. Based upon current market conditions and our estimates, our capital expenditures for 2009 should be within our anticipated cash flow from operations. For 2009, due to our reduced capital budget when compared to previous years, we anticipate a decrease in production volumes from 2008 levels and we will not fully replace reserves produced in 2009. We may also increase our capital expenditure budget if commodity prices rise during the year or if strategic opportunities warrant. If 2009 capital expenditures exceed our cash flow from operating activities, we anticipate funding those expenditures with our credit facility.

Our 2009 capital expenditures are expected to include drilling up to three horizontal wells in the Olmos sands in our AWP field, drilling a well in the Eagle Ford shale formation of our AWP field, drilling an exploratory well in our Southeast Louisiana core area along with completing a pipeline from our existing Shasta well to the Westside facility, facility projects in our Bay de Chene field, recompletions in our Southeast Louisiana core area, and fracture enhancements in our South Texas core area. We also plan to drill up to 10 additional wells to shallow and intermediate depths in our Southeast Louisiana core area.

Also in the Lake Washington and Bay de Chene fields during 2009, we plan on continuing to work on our 3D seismic depth migration of the merged data sets with an updated "salt model." We also completed a pilot seismic "pore-pressure" prediction project. This has allowed us to increase our confidence level as we begin to drill some of the deeper and higher impact wells in this area of South Louisiana. For example, we have successfully completed our Shasta prospect well and are preparing to hook this up to facilities. We have recently completed drilling one of our West Newport prospects and are preparing to complete this well. A full inventory of deep and higher impact tests have been developed for future drilling. This includes developing and planning a sub-salt exploratory test, which could be drilled next year dependant upon the commodity pricing environment.

Results of Continuing Operations — Years Ended 2008, 2007, and 2006

Revenues. Our revenues in 2008 increased by 25% compared to revenues in 2007 primarily due to higher oil and gas prices partially offset by decreased production from our Southeast Louisiana core area. Our revenues in 2007 increased by 19% compared to 2006 revenues due to increases in oil production from our Southeast Louisiana area and increases in oil prices. Revenues for 2008, 2007, and 2006 were substantially comprised of oil and gas sales. Crude oil production was 54% of our production volumes in 2008, 66% in 2007, and 71% in 2006. Natural gas production was 34% of our production volumes in 2008, 26% in 2007, and 24% in 2006.

Our properties are divided into the following core areas: The Southeast Louisiana core area includes the Lake Washington and Bay de Chene fields. The Central Louisiana/East Texas core area includes the Brookeland, Masters Creek, and South Bearhead Creek fields. The South Louisiana core area includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, and Bayou Penchant fields. The South Texas core area includes the AWP, Briscoe Ranch, Las Tiendas, and Sun TSH fields. The most significant property in our Strategic Growth category is the High Island field. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2008, 2007, and 2006:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Sales Volumes (MBoe)		
	2008	2007	2006	2008	2007	2006
S. E. Louisiana	$ 486.4	$ 477.0	$ 416.4	5,323	7,178	6,772
South Texas	158.6	72.0	61.7	2,793	1,517	1,437
Central Louisiana / E. Texas	81.6	48.7	35.1	996	872	745
South Louisiana	56.7	45.3	17.1	765	848	331
Strategic Growth	10.6	9.9	7.2	172	202	164
Total	$ 793.9	$ 652.9	$ 537.5	10,049	10,617	9,449

Our 2008 production was adversely affected by Hurricanes Gustav and Ike. As a result of these hurricanes, approximately 0.8 MBoe of production was shut-in during 2008 predominantly in Southeast Louisiana.

Oil and gas sales in 2008 increased by 22%, or $141.0 million, from the level of those revenues for 2007, and our net sales volumes in 2008 decreased by 5%, or 0.6 MMBoe, over net sales volumes in 2007. Average prices for oil increased to $101.38 per Bbl in 2008 from $71.92 per Bbl in 2007. Average natural gas prices increased to $8.54 per Mcf in 2008 from $6.42 per Mcf in 2007. Average NGL prices increased to $57.15 per Bbl in 2008 from $49.72 per Bbl in 2007.

In 2008, our $141.0 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $212.3 million favorable impact on sales, of which $159.7 million was attributable to the 41% increase in average oil prices received, $9.0 million was attributable to the 15% increase in NGL prices, and $43.6 million was attributable to the 33% increase in average natural gas prices received; and

- Volume variances that had a $71.3 million unfavorable impact on sales, with $116.9 million of decreases attributable to the 1.6 million Bbl decrease in oil sales volumes, partially offset by both an increase of $21.7 million due to the 0.4 million Bbl increase in NGL sales volumes, and an increase of $23.9 million due to the 3.7 Bcf increase in natural gas sales volumes.

Oil and gas sales in 2007 increased by 21%, or $115.3 million, from the level of those revenues for 2006, and our net sales volumes in 2007 increased by 12%, or 1.2 MMBoe, over net sales volumes in 2006. Average prices for oil increased to $71.92 per Bbl in 2007 from $64.28 per Bbl in 2006. Average natural gas prices were virtually unchanged at $6.42 per Mcf in 2007 compared to $6.44 per Mcf in 2006. Average NGL prices increased to $49.72 per Bbl in 2007 from $38.70 per Bbl in 2006.

In 2007, our $115.3 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $61.8 million favorable impact on sales, of which $53.8 million was attributable to the 12% increase in average oil prices received, and $8.5 million was attributable to the 28% increase in NGL prices, partially offset by a decrease of $0.5 million attributable to the $0.02 per Mcf decrease in natural gas prices; and

- Volume variances that had a $53.5 million favorable impact on sales, with $20.9 million of increases attributable to the 0.3 million Bbl increase in oil sales volumes, $12.1 million due to the 0.3 million Bbl increase in NGL sales volumes, and $20.5 million due to the 3.2 Bcf increase in natural gas sales volumes.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Sales Volume				Average Sales Price		
	Oil	NGL	Gas	Combined	Oil	NGL	Natural Gas
	(MBbl)	(MBbl)	(Bcf)	(MBoe)	(Bbl)	(Bbl)	(Mcf)
2006:							
First	1,487	90	3.3	2,127	$60.56	$39.75	$7.42
Second	1,554	70	3.4	2,184	$69.40	$40.85	$6.12
Third	1,825	159	3.3	2,537	$69.54	$42.37	$6.07
Fourth	1,855	141	3.6	2,601	$57.82	$32.82	$6.20
Total	6,721	460	13.6	9,449	$64.28	$38.70	$6.44
2007:							
First	1,773	133	3.8	2,534	$57.87	$39.90	$5.92
Second	1,872	134	3.5	2,589	$66.20	$44.22	$7.56
Third	1,783	190	4.4	2,702	$76.20	$48.89	$5.68
Fourth	1,617	317	5.1	2,792	$89.23	$56.65	$6.62
Total	7,045	774	16.8	10,617	$71.92	$49.72	$6.42
2008:							
First	1,420	316	5.0	2,570	$99.43	$59.80	$7.97
Second	1,482	290	5.5	2,694	$125.20	$67.73	$10.49
Third	1,171	294	5.1	2,319	$122.71	$70.55	$9.70
Fourth	1,347	311	4.9	2,466	$58.70	$32.00	$5.68
Total	5,420	1,211	20.5	10,049	$101.38	$57.15	$8.54

During 2008, 2007, and 2006, we recognized net gains of $26.1 million, $0.2 million, and $4.0 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. Had these gains been recognized in the oil and gas sales account, our average oil sales price would have been $105.32, $71.91 and $64.58 for 2008, 2007, and 2006, respectively, and our average natural gas sales price would have been $8.77, $6.43 and $6.59 for 2008, 2007, and 2006, respectively.

In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in “Price-risk management and other, net,” for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We recorded $14.1 million of the property related settlement as a reduction to “Proved properties” on the accompanying consolidated balance sheet, as this related to reimbursement of capital costs we incurred. We also recorded $8.7 million of the property related settlement as a reduction to “Lease operating cost” on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced “Proved properties” as a reduction of “Cash Used in Investing Activities – continuing operations” and the remainder of the insurance settlement was recorded as an increase to “Cash Provided by Operating Activities - continuing operations.”

Costs and Expenses. Our expenses in 2008 increased $824.0 million, or 201%, compared to 2007 expenses for the reasons noted below.

Our 2008 general and administrative expenses, net, increased $4.5 million, or 13%, from the level of such expenses in 2007, while 2007 general and administrative expenses, net, increased $6.5 million, or 24%, over 2006 levels. The increases in both 2008 and 2007 were primarily due to increased salaries and burdens associated with our expanded workforce, but were also impacted by increased restricted stock grants each year. Costs also increased in 2007 due to ongoing support costs of our new computer system implemented in 2007. For the years 2008, 2007, and 2006, our capitalized general and administrative costs totaled $30.1 million, $26.4 million, and $24.1 million, respectively. Our net general and administrative expenses per Boe produced increased to $3.85 per Boe in 2008 from $3.22 per Boe in 2007 and $2.92 per Boe in 2006. The portion of supervision fees recorded as a reduction to general and administrative expenses was $15.8 million for 2008, $11.8 million for 2007, and $8.7 million for 2006.

DD&A increased $33.9 million, or 18%, in 2008, from 2007 levels and increased $49.1 million, or 35% in 2007, from 2006 levels. The increase in 2008 was due to increases in the depletable oil and natural gas property base and lower reserves volumes, partially offset by lower production and lower future development costs. The increase in 2007 was due to increases in the depletable oil and natural gas property base, including future development costs and higher production, partially offset by higher reserves volumes. Industry costs for goods and services have increased over the last three year period and have contributed to the increase in our DD&A expense. Our DD&A rate per Boe of production was $22.12 in 2008, $17.74 in 2007, and $14.74 in 2006, resulting from increases in per unit cost of reserves additions.

We recorded $2.0 million, $1.4 million, and $0.9 million of accretions to our asset retirement obligation in 2008, 2007, and 2006, respectively.

Our lease operating costs increased $34.0 million, or 48%, over the level of such expenses in 2007, while 2007 costs increased $20.9 million, or 42% over 2006 levels. Lease operating costs increased during 2008 due to additional costs from properties acquired in the fourth quarter of 2007, increased work-over costs, increasing costs for industry goods and services and higher natural gas and NGL processing costs in 2008. Clean-up and repair costs related to hurricanes Gustav and Ike totaled $3.7 million in 2008. These costs increased in 2007 due to higher production, including costs from properties acquired in the fourth quarter of 2007, increasing costs for industry goods and services and higher natural gas and NGL processing costs in 2007. A portion of the increase in 2007 was from increased well insurance premiums which increased after hurricanes Katrina and Rita. Our lease operating costs per Boe produced were $10.44, $6.68, and $5.29 in 2008, 2007, and 2006, respectively.

Severance and other taxes increased $6.6 million, or 9%, over 2007 levels, while in 2007 these taxes increased $12.6 million, or 21% over 2006 levels. The increases in 2008 were due primarily to higher commodity prices, offset slightly by lower production. In 2007 they were caused by higher commodity prices and increased production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 10.1%, 11.3% and 11.4% in 2008, 2007 and 2006, respectively. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana decreased in 2008, the overall percentage of severance costs to sales also decreased.

Our total interest cost in 2008 was $39.1 million, of which $8.0 million was capitalized. Our total interest cost in 2007 was $37.6 million, of which $9.5 million was capitalized. Our total interest cost in 2006 was $32.8 million, of which $9.2 million was capitalized. Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $12.0 million in both 2008 and 2007 and $11.9 million in 2006. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002 and retired in 2007, including amortization of debt issuance costs, totaled $8.9 million in 2007 and $19.2 million in 2006. Interest expense on our 7-1/8% senior notes due 2017 and issued in June 2007, including amortization of debt issuance costs, totaled $18.1 million in 2008 and $10.6 million in 2007. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $8.6 million in 2008, $6.1 million in 2007, and $1.5 million in 2006. Other interest cost was $0.1 million in each of 2008, 2007 and 2006. We capitalize a portion of interest related to unproved properties. The increase in interest expense in 2008 and 2007 was primarily due to an increase in borrowings against our line of credit facility for our fourth quarter 2007 property acquisition in South Texas, partially offset by an increase in capitalized interest costs.

In 2007, we incurred $12.8 million of debt retirement costs related to the redemption of our 9-3/8% senior notes due 2012. The costs were comprised of approximately $9.4 million of premiums paid to repurchase the notes, and $3.4 million to write-off unamortized debt issuance costs.

In the fourth quarter of 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and natural gas properties.

Our overall effective tax rate was 37.7% for 2008, 37.6% for 2007 and 39.2% for 2006. The effective tax rate for 2008, 2007, and 2006 was higher than the statutory rate primarily because of state income taxes. Valuation allowances also contributed to the 2007 and 2006 effective rates.

Income (Loss) from Continuing Operations. Our income (loss) from continuing operations for 2008 of $(257.1) million was significantly lower than our 2007 income from continuing operations of $152.6 million due to the write-down of oil and gas properties in the fourth quarter of 2008, partially offset by higher oil and gas sales.

Our income from continuing operations in 2007 of $152.6 million was 1% higher than our 2006 income from continuing operations of $151.1 million mainly due to higher oil prices.

Net Income (Loss). Our net income (loss) in 2008 of $(260.5) million was significantly lower than our 2007 net income of $21.3 million, due to the write-down of oil and gas properties, offset by higher oil and gas sales.

Our net income in 2007 of $21.3 million was 87% lower than our 2006 net income of $161.6 million mainly due to our loss from discontinued operations of $131.3 million in the 2007 period.

Full-Cost Ceiling Test

As described in footnote 1 of the Notes to Consolidated Financial Statements (“Significant Accounting Policies”), at the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (“Ceiling Test”). We did not have any outstanding derivative instruments at December 31, 2008 that would affect this calculation.

In 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and natural gas properties.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

Discontinued Operations

In December 2007, Swift agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations for 2007 and 2008 have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift Energy for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the permit sale, and have deferred the potential gain on this property sale pending the outcome of this litigation.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets. During the fourth quarter of 2007 and the full year of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded non-cash asset write-downs of $143.2 million and $3.6 million, respectively, related to these assets. These write-downs are recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying condensed consolidated statements of income.

As of December 31, 2008, operations in New Zealand had represented less than 1% of our total assets and approximately 4% of our 2008 sales volumes. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported under discontinued operations. The following table summarizes selected data pertaining to discontinued operations (in thousands except per share and per Boe amounts):

	2008	2007	2006
Oil and gas sales	$ 14,675	$ 42,394	$ 64,039
Other revenues	832	1,221	862
Total revenues	15,507	43,615	64,901
Depreciation, depletion, and amortization	4,857	23,147	30,051
Other operating expenses	10,750	22,491	20,872
Non-cash write-down of property and equipment	3,572	143,152	---
Total expenses	19,179	188,790	50,923
Income (Loss) from discontinued operations before income taxes	(3,672)	(145,175)	13,978
Income tax expense (benefit)	(312)	(13,874)	3,487
Income (Loss) from discontinued operations, net of taxes	$ (3,360)	$ (131,301)	$ 10,491
Earnings per common share from discontinued operations, net of taxes-diluted	$ (0.11)	$ (4.29)	$ 0.35
Total sales volumes (MBoe)	415	1,387	2,252
Oil sales volumes (MBbls)	58	225	469
Natural gas sales volumes (Bcf)	1.8	5.9	9.2
NGL sales volumes (MBbls)	52	177	253
Average sales price per Boe	$ 35.37	$ 30.56	$ 28.43
Oil sales price per Bbl	$ 108.16	$ 75.78	$ 67.06
Natural gas sales price per Mcf	$ 3.55	$ 3.36	$ 2.99
NGL sales price per Bbl	$ 37.66	$ 30.91	$ 20.22
Lease operating cost per Boe	$ 15.29	$ 9.93	$ 5.56
Total assets	$ 564	$ 110,585	$ 235,997
Cash flow provided by operating activities	$ 6,039	$ 25,620	$ 41,680
Capital expenditures	$ 1,273	$ 9,466	$ 56,707

Loss from discontinued operations, net of tax, for 2008 decreased compared to 2007 as the majority of our assets were sold in 2008 and day to day operations ceased. Our capitalized general and administrative expenses were immaterial for 2008 and for years 2007 and 2006 were $4.2 million, and $4.1 million.

Income (Loss) from discontinued operations, net of tax, for 2007 decreased compared to 2006 primarily due to the non-cash write-down of property and equipment, a decrease in produced oil and natural gas volumes which reduced revenues, partially offset by a tax benefit associated with the non-cash write-down of property and equipment, along with lower depletion expense due to lower production volumes.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and over the last six months that volatility has increased to extreme levels, and low prices are expected to continue for 2009 and possibly future periods. The price of oil began to decline in the third quarter of 2008, price declines accelerated in the fourth quarter of 2008, and have further decreased during the first quarter of 2009. Factors such as worldwide economic conditions and credit availability, worldwide supply disruptions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices remained high during much of 2008 when compared to longer-term historical prices but began falling in the third quarter of 2008 and have continued to fall into the first quarter of 2009. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Credit Risk Due to Certain Concentrations

We extend credit, primarily in the form of uncollateralized oil and natural 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. Credit losses in 2008 and 2007 have been immaterial, but given the downturn in the industry we have examined every one of our purchasers of oil and gas for credit worthiness. 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. For 2008 and 2007, oil and gas sales to Shell Oil Corporation and affiliates were 29% and 42% of total oil and gas sales, respectively; while during 2008 and 2007, Chevron Corporation and its affiliates accounted for 25% and 22% of our total oil and gas sales, respectively. From certain customers we also obtain letters of credit or parent company guaranties, if applicable, to reduce risk of loss.

Commitments and Contingencies

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 natural gas wells. In management’s opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

Liquidity and Capital Resources

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling prices for oil and natural gas, all of which began in the third quarter of 2008, will have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. See “Overview – Financial Condition.”

Net Cash Provided by Operating Activities. For 2008, our net cash provided by operating activities from continuing operations was $582.0 million, representing a 32% increase as compared to $442.3 million generated during 2007. The $139.7 million increase in 2008 was primarily due to an increase of $166.7 million in revenues, mainly attributable to higher oil and natural gas prices during the first part of the year, offset in part by lower production and higher lease operating costs and severance taxes due to higher oil and gas sales. For 2007, our net cash provided by operating activities from continuing operations was $442.3 million, representing a 15% increase as compared to $383.2 million generated during 2006. The $59.0 million increase in 2007 was primarily due to an increase of $115.3 million in oil and gas sales, attributable to higher oil prices and production, offset in part by higher lease operating costs and severance taxes due to higher oil prices and higher production.

Accounts Receivable. We assess the collectability of accounts receivable, and, based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both December 31, 2008 and 2007, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balances on the accompanying balance sheets.

At December 31, 2008, we had $11.8 million in receivables for concluded oil hedges covering 2008 production which are recognized on the accompanying balance sheet in “Other Receivables” and were subsequently collected in January 2009.

Existing Credit Facility. We had borrowings of $180.7 million under our bank credit facility at December 31, 2008, and $187.0 million in borrowings at December 31, 2007. Our bank credit facility at December 31, 2008 consisted of a $500.0 million revolving line of credit with a $400.0 million borrowing base. Effective November 1, 2008, our lenders reaffirmed our borrowing base and commitment amount as part of their normal recurring borrowing base review which occurs every six months. The borrowing base was increased by our bank group from $350.0 million to $400.0 million in November 2007. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. In September 2007, we increased the commitment amount from $250.0 million to $350.0 million. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement and expect to remain in compliance with these provisions in 2009 and future periods. Our access to funds from our credit facility is not restricted under any “material adverse condition” clause, a clause that is common for credit agreements to include. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect. Our available borrowings under our line of credit facility provide us liquidity.

In light of recent credit market volatility, many financial institutions have experienced liquidity issues, and governments have intervened in these markets to create liquidity. We have reviewed the creditworthiness of the banks that fund our credit facility and thus far our bank liquidity has not been impacted. However, if the current credit market volatility is prolonged, future extensions of our credit facility may contain terms and interest rates not as favorable as those of our current credit facility. The borrowing base of $400.0 million was reaffirmed effective November 1, 2008 as part of the normal recurring semi-annual re-determination. The next scheduled borrowing base review is May 2009, and it is possible the borrowing base and commitment amounts could be reduced due to lower oil and gas prices and the current state of the financial and credit markets.

Working Capital. Our working capital decreased from a deficit of $10.2 million at December 31, 2007, to a deficit of $75.4 million at December 31, 2008. The decrease primarily resulted from the sale of our New Zealand assets in 2008 which were classified as current assets held for sale, along with lower oil and gas receivables due to lower oil and gas prices at year-end, partially offset by a decrease in accounts payable and accrued capital costs.

Debt Retirements and Debt Issuances. In June 2007, we issued $250.0 million of 7-1/8% senior notes due 2017. In June 2007, we redeemed all $200.0 million of 9-3/8% senior subordinated notes due 2012 and recorded a charge of $12.8 million related to the redemption of these notes, which is recorded in “Debt retirement costs” on the accompanying condensed consolidated statement of income. The costs were comprised of approximately $9.4 million of premium paid to redeem the notes, and $3.4 million to write-off unamortized debt issuance costs.

Debt Maturities. Our credit facility, with a balance of $180.7 million at December 31, 2008, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $250.0 million of 7-1/8% senior notes mature June 1, 2017.

Capital Expenditures. In 2008, we relied upon our net cash provided by operating activities from continuing operations of $582.0, cash proceeds from the sale of most of our New Zealand assets of $82.7 million, and cash balances to fund capital expenditures of $674.8 million including $46.5 million of acquisitions.

We have spent considerable time and capital on facility capacity upgrades and additions in the Lake Washington field. Since acquiring the property, we have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility. During 2008, we completed the addition of a fourth production platform, the Westside facility, which increased our processing capacity another 10,000 barrels per day.

We completed 110 of 126 wells in during 2008, for a completion rate of 87%. A total of 23 development wells were completed in the Lake Washington field, and 41 out of 44 development wells were completed in the AWP field. In each of the Bay de Chene and South Bearhead Creek fields, we completed five development wells, and we completed 30 of 39 development wells in the Sun TSH and Briscoe Ranch fields, completed two development wells in the Horseshoe Bayou/Bayou Sale field, completed one out of three development wells in the Jeanerette field, drilled one unsuccessful development well in the Masters Creek field, and drilled one successful non-operated well in Alabama. We also completed one exploratory well in each of the Bay de Chene and Cote Blanche Island fields, and drilled one unsuccessful exploratory well in the High Island field.

Our capital expenditures were approximately $650.6 million in 2007 and $488.2 million in 2006. In 2007, we relied upon our net cash provided by operating activities from continuing operations of $442.3, credit facility borrowings of $155.6 million, and cash balances to fund capital expenditures of $650.6 million including $252.3 million of acquisitions. During 2006, we relied upon our net cash provided by operating activities from continuing operations of $383.2 million, bank borrowings of $31.4 million, and cash balances to fund capital expenditures of $488.2 million, including acquisitions of $194.3 million.

In 2007, we participated in drilling 64 development wells and five exploratory wells, of which 59 development wells and two exploratory wells were completed.

In response to lower commodity prices, the Company has reduced its capital expenditure budget for 2009 and anticipates lower capital expenditures in 2009 than in 2008. Because our exploration and development activities are to a degree scalable, we anticipate being able to adjust our capital expenditures to the level of cash flow from operations, supplemented with funds available under our credit facility.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2008 are as follows:

	2009	2010	2011	2012	2013	Thereafter	Total
				(in thousands)			
Non-cancelable operating leases (1)	$ 7,990	$ 7,002	$ 5,900	$ 6,037	$ 6,158	$ 7,466	$ 40,553
Asset retirement obligation (2)	480	1,500	2,450	3,450	3,900	37,005	48,785
Drilling rigs, seismic services, and pipe inventory	8,089	—	—	—	—	—	8,089
7-5/8% senior notes due 2011 (3)	—	—	150,000	—	—	—	150,000
7-1/8% senior notes due 2017 (3)	—	—	—	—	—	250,000	250,000
Credit facility (4)	—	—	180,700	—	—	—	180,700
Total	$ 16,559	$ 8,502	$ 339,050	$ 9,487	$ 10,058	$ 294,471	$ 678,127

(1) Our most significant office lease is in Houston, Texas and it extends until 2015.

(2) Amounts shown by year are the fair values at December 31, 2008.

(3) Amounts do not include the interest obligation, which is paid semiannually.

(4) The credit facility expires in October 2011 and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

Proved Oil and Gas Reserves

At year-end 2008, our proved reserves were 116.4 MMBoe with a PV-10 Value of $1.4 billion (PV-10 is a non-GAAP measure, see the section titled “Oil and Natural Gas Reserves” in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). In 2008, our proved natural gas reserves decreased 51.4 Bcf, or 15%, while our proved oil reserves decreased 8.6 MMBbl, or 15%, and our NGL reserves decreased 0.1 MMBbl, or 1%, for a total equivalent decrease of 17.3 MMBoe, or 13%. In 2007, our domestic proved natural gas reserves increased 74.1 Bcf, or 27%, while our proved oil reserves decreased 3.7 MMBbl, or 6%, and our NGL reserves increased 6.7 MMBbl, or 58%, for a total equivalent increase of 15.4 MMBoe, or 13%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 5.7 MMBoe of proved reserves in 2008, 12.9 MMBoe in 2007, and 11.9 MMBoe in 2006. Through acquisitions we added 1.0 MMBoe of proved reserves in 2008, 12.9 Bcfe in 2007, and 13.0 Bcfe in 2006. At year-end 2008, 53% of our total proved reserves were proved developed, compared with 48% at year-end 2007 and 47% at year-end 2006.

The PV-10 Value of our domestic proved reserves at year-end 2008 decreased 64% from the PV-10 Value at year-end 2007. Natural gas prices decreased at year-end 2008 to $4.96 per Mcf from $6.65 per Mcf at year-end 2007, compared to $5.84 per Mcf at year-end 2006. Oil prices decreased at year-end 2008 to $44.09 per Bbl from $93.24 per Bbl at year-end 2007, compared to $60.07 in 2006. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant for that year’s reserves calculation throughout the life of the properties. Subsequent changes to such year-end oil and natural gas prices could have a significant impact on the calculated PV-10 Value. As noted in Footnote 1 of the Notes to Consolidated Financial Statements, in December 2008 the SEC issued a release which changes the accounting and disclosure requirements surrounding oil and gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. This release is effective for financial statements issued for fiscal years and interim periods beginning on or after January 1, 2010.

Income Taxes

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. Under SFAS No. 109, "Accounting for Income Taxes," deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. In the 4th quarter of 2008 we recorded additional tax expense and increased other long-term liabilities by $0.3 million, which increased our total balance of our unrecognized tax benefits to $1.3 million. If recognized, these tax benefits would fully impact our effective tax rate.

We do not believe the total of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2008, we have accrued $0.3 million for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns from 1998 through 2003 and 2005 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

In the third quarter of 2007, we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company's property disposition plans and increased income tax expense of $2.6 million in that period. Subsequently, all but $1.1 million of our capital loss carryforward assets have expired, and we continue to carry a valuation allowance for the full remaining balance.

Critical Accounting Policies and New Accounting Pronouncements

See the list of significant accounting policies in Note 1 to the consolidated financial statements.

Related-Party Transactions

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee, and controlled and majority owned by the aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.7 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2008, $0.6 million in 2007 and $0.5 million in 2006. The contract was renewed June 30, 2007, on substantially the same terms as the previous contract and expires June 30, 2010. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are presented and considered by the Corporate Governance Committee of our Board of Directors.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, cash flows, available borrowing capacity, liquidity, acquisition plans, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as “plan,” “future,” “estimate,” “expect,” “budget,” “predict,” “anticipate,” “projected,” “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 from those projected. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices; availability of services and supplies; disruption of operations and damages due to hurricanes or tropical storms; 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 and availability of capital; conditions in the financial and credit markets; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements.

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. Significant declines in oil and natural gas prices began in the last four months of 2008, and the effects of such pricing volatility are expected to continue into 2009.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At December 31, 2008, we had no outstanding derivative instruments in place for 2009 production.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2008, we had borrowings of $180.7 million under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our 2009 cash flows based on this same level of borrowing.

Income Tax Carryforwards. As of December 31, 2008, the Company has net tax carryforwards assets of $16.0 million for federal net operating losses, $14.5 for federal alternative minimum tax credits and $7.4 million for state tax net operating loss carryforwards which in management's judgment will more likely than not be utilized to offset future taxable earnings. We also have a $1.1 million capital loss carryforward asset that in management's judgment has a less than more likely than not probability of being utilized. Accordingly, the capital loss carryover asset has been fully offset by a valuation allowance.

The Company's New Zealand subsidiaries have local income tax loss carryovers which are available if any future income is generated by these entities. As of December 31, 2008 the estimated U.S. dollar value of these loss carryover assets is $25.8 million. In management's judgment it is less than more likely than not that the remaining carryover assets will be utilized. Accordingly, these carryover assets have been fully offset by a valuation allowance.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2008 and 2007, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2008 and 2007, the fair value of our senior notes due 2017, were $175.0 million, or 70% of face value, and $237.5 million, or 95.0% of face value, respectfully. Based upon quoted market prices as of December 31, 2008 and 2007, the fair values of our senior notes due 2011 were $132.8 million, or 88.5% of face value, and $150.8 million, or 100.5% of face value, respectfully. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2008 and 2007. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2008 and 2007.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers From certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Item 8. Financial Statements and Supplementary Data	Page
Management's Report on Internal Control Over Financial Reporting	45
Reports of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting	46
Reports of Independent Registered Public Accounting Firm on Consolidated Financial Statements	47
Consolidated Balance Sheets	48
Consolidated Statements of Income	49
Consolidated Statements of Stockholders' Equity	50
Consolidated Statements of Cash Flows	51
Notes to Consolidated Financial Statements	52
1. Summary of Significant Accounting Policies	52
2. Earnings Per Share	57
3. Provision (Benefit) for Income Taxes	58
4. Long-Term Debt	60
5. Commitments and Contingencies	62
6. Stockholders' Equity	62
7. Related-Party Transactions	66
8. Discontinued Operations	66
9. Acquisitions and Dispositions	68
10. Fair Value Measurements	69
11. Condensed Consolidating Financial Information	69
Supplementary Information	73
Oil and Gas Operations (Unaudited)	73
Selected Quarterly Financial Data (Unaudited)	78

Management's Report on Internal Control Over Financial Reporting

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

Management of the Company assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2008.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance of achieving their control objectives. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2008, based on their audit. The Public Company Accounting Oversight Board (United States) standards require that they plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Their audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as they considered necessary in the circumstances.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited Swift Energy Company and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 25, 2009 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 25, 2009

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective January 1, 2007 the Company adopted Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 25, 2009

Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Year Ended December 31,	
	2008	2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$283	$5,623
Accounts receivable-		
Oil and gas sales	37,364	72,916
Joint interest owners	4,235	1,587
Other Receivables	20,065	1,324
Deferred tax asset	---	8,055
Other current assets	15,575	13,896
Current assets held for sale	564	96,549
Total Current Assets	78,086	199,950
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	3,270,159	2,610,469
Unproved properties	91,252	106,643
	3,361,411	2,717,112
Furniture, fixtures, and other equipment	37,669	33,064
	3,399,080	2,750,176
Less – Accumulated depreciation, depletion, and amortization	(1,967,633)	(989,981)
	1,431,447	1,760,195
Other Assets:		
Deferred Charges	6,107	7,252
Other Long-Term assets	1,648	1,654
	7,755	8,906
	$1,517,288	$1,969,051
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$66,802	$89,281
Accrued capital costs	74,315	94,947
Accrued interest	7,207	7,558
Undistributed oil and gas revenues	5,175	10,309
Current liabilities associated with assets held for sale	---	8,066
Total Current Liabilities	153,499	210,161
Long-Term Debt	580,700	587,000
Deferred Income Taxes	130,899	302,303
Asset Retirement Obligation	48,785	31,066
Other Long-Term Liabilities	2,528	2,467
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, 31,336,472 and 30,615,010 shares issued, and 30,868,588 and 30,178,596 shares outstanding respectively	313	306
Additional paid-in capital	435,307	407,464
Treasury stock held, at cost, 467,884 and 436,414 shares, respectively	(10,431)	(7,480)
Retained earnings	175,688	436,178
Accumulated other comprehensive loss, net of income tax	---	(414)
	600,877	836,054
	$1,517,288	$1,969,051

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Year Ended December 31, 2008	2007	2006
Revenues:			
Oil and gas sales	$ 793,859	$ 652,856	$ 537,513
Price-risk management and other, net	26,956	1,265	13,323
	820,815	654,121	550,836
Costs and Expenses:			
General and administrative, net	38,673	34,182	27,634
Depreciation, depletion, and amortization	222,288	188,393	139,245
Accretion of asset retirement obligation	1,958	1,437	884
Lease operating cost	104,874	70,893	49,948
Severance and other taxes	80,403	73,813	61,235
Interest expense, net	31,079	28,082	23,582
Debt retirement cost	---	12,765	---
Write-down of oil and gas properties	754,298	---	---
	1,233,573	409,565	302,528
Income (Loss) from Continuing Operations Before Income Taxes	(412,758)	244,556	248,308
Provision (Benefit) for Income Taxes	(155,628)	91,968	97,234
Income (Loss) from Continuing Operations	(257,130)	152,588	151,074
Income (Loss) from Discontinued Operations, net of taxes	(3,360)	(131,301)	10,491
Net Income (Loss)	$ (260,490)	$ 21,287	$ 161,565
Per Share Amounts-			
Basic: Income (Loss) from Continuing Operations	$ (8.39)	$ 5.09	$ 5.16
Income (Loss) from Discontinued Operations, net of taxes	(0.11)	(4.38)	0.36
Net Income (Loss)	$ (8.50)	$ 0.71	$ 5.52
Diluted: Income (Loss) from Continuing Operations	$ (8.39)	$ 4.98	$ 5.03
Income (Loss) from Discontinued Operations, net of taxes	(0.11)	(4.29)	0.35

Net Income (Loss)	$	(8.50)	$	0.69	$	5.38
Weighted Average Shares Outstanding		30,661		29,984		29,265

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries
(in thousands, except per share amounts)

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2005	$ 295	$ 365,086	$ (6,446)	$ (5,850)	$ 254,303	$ (70)	$ 607,318
Stock issued for benefit plans (22,358 shares)	-	714	321	-	-	-	1,035
Stock options exercised (652,829 shares)	7	11,831	-	-	-	-	11,838
Adoption of SFAS No. 123R	-	(5,875)	-	5,850	-	-	(25)
Tax benefits from stock compensation	-	4,811	-	-	-	-	4,811
Employee stock purchase plan (22,425 shares)	-	671	-	-	-	-	671
Issuance of restricted stock (35,776 shares)	-	-	-	-	-	-	-
Amortization of stock compensation	-	10,318	-	-	-	-	10,318
Comprehensive income:							
Net income	-	-	-	-	161,565	-	161,565
Other comprehensive income	-	-	-	-	-	386	386
Total comprehensive income							161,951
Balance, December 31, 2006	$ 302	$ 387,556	$ (6,125)	$ -	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares)	-	953	471	-	-	-	1,424
Stock options exercised (239,650 shares)	2	3,168	-	-	-	-	3,170
Purchase of treasury shares (42,145 shares)	-	-	(1,826)	-	-	-	(1,826)
Adoption of FIN 48	-	-	-	-	(977)	-	(977)
Tax benefits from stock compensation	-	613	-	-	-	-	613
Employee stock purchase plan (17,678 shares)	-	619	-	-	-	-	619
Issuance of restricted stock (187,678 shares)	2	(2)	-	-	-	-	-

Amortization of stock compensation	-	14,557	-	-	-	-	14,557
Comprehensive income:							
Net income	-	-	-	-	21,287	-	21,287
Other comprehensive loss	-	-	-	-	-	(730)	(730)
Total comprehensive income							20,557
Balance, December 31, 2007	$ 306	$ 407,464	$ (7,480)	$ -	$ 436,178	$ (414)	$ 836,054
Stock issued for benefit plans (39,152 shares)	-	1,018	671	-	-	-	1,689
Stock options exercised (420,721 shares)	4	8,295	-	-	-	-	8,299
Purchase of treasury shares (70,622 shares)	-	-	(3,622)	-	-	-	(3,622)
Tax benefits from stock compensation	-	1,422	-	-	-	-	1,422
Employee stock purchase plan (25,645 shares)	-	944	-	-	-	-	944
Issuance of restricted stock (275,096 shares)	3	(3)	-	-	-	-	-
Amortization of stock compensation	-	16,167	-	-	-	-	16,167
Comprehensive loss:							
Net loss	-	-	-	-	(260,490)	-	(260,490)
Other comprehensive income	-	-	-	-	-	414	414
Total comprehensive loss							(260,076)
Balance, December 31, 2008	$ 313	$ 435,307	$ (10,431)	$ -	$ 175,688	$ -	$ 600,877

(1)$.01 par value.

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries
(in thousands)

	Year Ended December 31,		
	2008	2007	2006
Cash Flows from Operating Activities:			
Net income loss)	$ (260,490)	$ 21,287	$ 161,565
Plus (income) loss from discontinued operations, net of taxes	3,360	131,301	(10,491)
Adjustments to reconcile net income (loss) to net cash provided by operation activities -			
Depreciation, depletion, and amortization	222,288	188,393	139,245
Write-down of oil and gas properties	754,298	---	---
Accretion of asset retirement obligation	1,958	1,437	884
Deferred income taxes	(164,498)	86,474	86,541
Stock-based compensation expense	11,631	10,317	6,905
Debt retirement cost – cash and non-cash	---	12,765	---
Other	(8,640)	(4,314)	7,117
Change in assets and liabilities-			
(Increase) decrease in accounts receivable	26,172	(9,114)	(20,571)
Increase (decrease) in accounts payable and accrued liabilities	(3,915)	5,748	10,906
Increase (decrease) in income taxes payable	214	(806)	884
Increase (decrease) in accrued interest	(351)	(1,206)	256
Cash Provided by operating activities – continuing operations	582,027	442,282	383,241
Cash Provided by operating activities – discontinued operations	6,039	25,620	41,680
Net Cash Provided by Operating Activities	588,066	467,902	424,921
Cash Flows from Investing Activities:			
Additions to property and equipment	(628,325)	(398,295)	(293,957)
Proceeds from the sale of property and equipment	144	250	24,678
Acquisition of properties	(46,472)	(252,299)	(194,269)
Net cash received as operator of partnerships			
and joint ventures	---	485	410
Other	---	---	(528)
Cash Used in investing activities – continuing operations	(674,653)	(649,859)	(463,666)
	80,504	(7,827)	(59,881)

Cash Provided By (Used in) investing activities – discontinued operations			
Net Cash Used in Investing Activities	(594,149)	(657,686)	(523,547)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	---	250,000	---
Payments of long-term debt	---	(200,000)	---
Net proceeds from (payments of) bank borrowings	(6,300)	155,600	31,400
Net proceeds from issuances of common stock	9,243	3,789	12,509
Excess tax benefits from stock-based awards	1,422	613	3,328
Purchase of treasury shares	(3,622)	(1,826)	---
Payments of debt retirement costs	---	(9,376)	---
Payments of debt issuance costs	---	(4,451)	(558)
Cash provided by financing activities – continuing operations	743	194,349	46,679
Cash provided by financing activities – discontinued operations	---	---	---
Net Cash Provided by financing activities	743	194,349	46,679
Net Increase (Decrease) in Cash and Cash Equivalents	$ (5,340)	$ 4,565	$ (51,947)
Cash and Cash Equivalents at Beginning of Year	5,623	1,058	53,005
Cash and Cash Equivalents at End of Year	$ 283	$ 5,623	$ 1,058
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 30,283	$ 28,092	$ 22,691
Cash paid during year for income taxes	$ 8,505	$ 2,113	$ 9,780

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Significant Accounting Policies

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

Discontinued Operations. Certain amounts have been reclassified to present the Company's New Zealand operations as discontinued operations. Unless otherwise indicated, information presented in the notes to the financial statements relates only to Swift's continuing operations. Information related to discontinued operations is included in Note 8 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers and their ability to withstand the credit crisis,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

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

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural 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 natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2008, 2007, and 2006, such internal costs capitalized totaled $30.1 million, $26.4 million, and $24.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2008, 2007, and 2006, capitalized interest on unproved properties totaled $8.0 million, $9.5 million, and $9.2 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and natural gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, recorded at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property 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, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). We did not have any outstanding derivative instruments at December 31, 2008 that would affect this calculation.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization ("DD&A") 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 estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

In 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million on our oil and natural gas properties.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

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 collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets. 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, 2008, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2008 and 2007, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Debt Issuance Costs. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the June 2004 extension of our bank credit facility, the public offering in June 2004 of our 7-5/8% senior notes due 2011, and the public offering in June 2007 of our 7-1/8% senior subordinated notes due 2017, were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility. The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at December 31, 2008, was $3.7 million, net of accumulated amortization of $0.5 million. The issuance costs associated with our revolving credit facility, which was extended in October 2006, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2008, was $0.7 million, net of accumulated amortization of $2.5 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2008, was $1.7 million, net of accumulated amortization of $2.3 million.

Insurance Claims. In 2008, we filed insurance claims related to 2008 Hurricanes Gustav and Ike. We anticipate our total cost for the replacement of assets, repairs, and clean-up costs related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will approximate $25 million and we believe a portion of this will be reimbursed by insurance coverage. During 2008, we incurred approximately $15 million of costs related to the hurricanes, both capital costs and lease operating expense, and expect the remainder of these costs will be incurred in the first two quarters of 2009 and mainly relate to capital projects.

In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in "Price-risk management and other, net," for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We also recorded $8.7 million of the property related settlement as a reduction to "Lease operating cost" on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced "Proved properties" as a reduction of "Net Cash Used in Investing Activities – Continuing Operations" and the remainder of the insurance settlement was recorded as an increase to "Net Cash Provided by Operating Activities – Continuing Operations."

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

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2008, 2007 and 2006, we recognized net gains of $26.1 million, $0.2 million, and $4.0 million, respectively, relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. Had these gains and losses been recognized in the oil and gas sales account they would not materially change our per unit sales prices received. At December 31, 2008, the Company had recorded no derivative gains or losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in “Price-risk management and other, net” for 2008, 2007, and 2006 was not material.

At December 31, 2008, we did not have any outstanding derivative instruments in place for future production. At December 31, 2007, we had in place oil price floors in effect for the contract months of January 2008 through March 2008 that covered a portion of our oil production for January 2008 to March 2008; and we also had in place natural gas price floors in effect for the contract months of February 2008 through March 2008 that covered a portion of our natural gas production for February to March 2008.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in “Accumulated other comprehensive income (loss), net of income tax.” When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from “Accumulated other comprehensive income (loss), net of income tax” and recorded in “Price-risk management and other, net” on the accompanying statements of income. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. At December 31, 2008, we had $11.8 million in receivables for concluded oil hedges covering 2008 production which are recognized on the accompanying balance sheet in “Other Receivables” and were subsequently collected in January 2009.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to “General and administrative, net.” Our supervision fees are based on COPAS determined rates. The amount of supervision fees charged in 2008 and 2007 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $15.8 million in 2008, $11.8 million in 2007, and $8.7 million in 2006.

Inventories. We value inventories at the lower of cost or market value. Inventory is accounted for using the first in, first out method (“FIFO”). Inventories consisting of materials, supplies, and tubulars are included in “Other current assets” on the accompanying balance sheets totaling $13.7 million at December 31, 2008 and $4.2 million at December 31, 2007.

Income Taxes. Under SFAS No. 109, “Accounting for Income Taxes,” deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Accounting for income taxes are described more fully in Note 3.

Accounts Payable and Accrued Liabilities. Included in “Accounts payable and accrued liabilities,” on the accompanying balance sheets, at December 31, 2008 and 2007 are liabilities of approximately $23.5 million and $12.6 million, respectively, which represent the amounts by which checks issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement 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 natural 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. From certain customers we also obtain letters of credit or parent company guaranties, if applicable, to reduce risk of loss. During 2008 and 2007, oil and gas sales to Shell Oil Company and affiliates were $228.4 million and $290.1 million, or 29% and 42% of total oil and gas sales, respectively. During 2008 and 2007, Chevron Corporation and its affiliates accounted for $202.0 million and $151.0 million, or 25% and 22% of our total oil and gas sales. Credit losses in 2008, 2007 and 2006 were immaterial.

Restricted Assets. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2008 and 2007, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2008 and 2007, the fair value of our senior notes due 2017, were $175.0 million, or 70.0% of face value, and $237.5 million, or 95.0% of face value, respectfully. Based upon quoted market prices as of December 31, 2008 and 2007, the fair values of our senior notes due 2011 were $132.8 million, or 88.5% of face value, and $150.8 million, or 100.5% of face value, respectfully. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2008 and 2007. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2008 and 2007.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2008, we had no balance in "Accumulated other comprehensive loss, net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2008 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2007	$ (658)	$ 244	$ (414)
Change in fair value of cash flow hedges	18,371	(6,779)	11,592
Effect of cash flow hedges settled during the period	(17,713)	6,535	(11,178)
Other comprehensive income (loss) at December 31, 2008	$ ---	$ ---	$ ---

Total comprehensive income (loss) was $(260.1) million, $20.6 million, and $162.0 million for 2008, 2007, and 2006, respectively.

Stock Based Compensation. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Upon adoption of SFAS No. 123R, we recorded an immaterial cumulative effect of a change in account principle and prior periods were not restated to reflect the impact of adopting SFAS No. 123R.

We have three stock-based compensation plans, which are described more fully in Note 6.

The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes-Merton option-pricing model with the following weighted average assumptions in 2008, 2007, and 2006, respectively: no dividend yield; expected volatility factors of 39.5%, 38.5%, and 39.3%; risk-free interest rates of 2.4%, 4.7%, and 4.8%; and expected lives of 4.1, 6.0, and 4.8 years. We viewed all awards of stock compensation as a single award with an expected life equal to the average expected life of underlying awards and amortized the award on a straight-line basis over the life of the award.

Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves 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 which is included in the full cost balance. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation.

The following provides a roll-forward of our asset retirement obligation (in thousands):

Asset Retirement Obligation as of January 1, 2006	$ 15,424
Accretion expense for 2006	884
Liabilities incurred for new wells and facilities construction	190
Liabilities incurred for acquisitions	12,207
Reductions due to sold and abandoned wells	(177)
Revisions in estimated cash flows	265
Asset Retirement Obligation as of December 31, 2006	$ 28,793
Accretion expense for 2007	1,438
Liabilities incurred for new wells and facilities construction	981
Liabilities incurred for acquisitions	620
Reductions due to sold and abandoned wells	(808)
Revisions in estimated cash flows	3,435
Asset Retirement Obligation as of December 31, 2007	$ 34,459
Accretion expense for 2008	1,958
Liabilities incurred for new wells and facilities construction	1,985
Liabilities incurred for acquisitions	218
Reductions due to sold and abandoned wells	(515)
Revisions in estimated cash flows	10,680
Asset Retirement Obligation as of December 31, 2008	$ 48,785

At December 31, 2008 and 2007, we had $0 and approximately $3.4 million of our asset retirement obligation classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets, respectively.

New Accounting Pronouncements. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure eligible assets and liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We will evaluate the impact of SFAS No. 141(R) on business combinations and related valuations as we have business acquisitions in the future.

In February 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. This standard was adopted on January 1, 2009. The adoption of this statement did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. This statement requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this statement only impacts disclosure requirements, the adoption of this statement did not have an impact on our financial position or results of operations.

In December 2008, the SEC issued release 33-8995, Modernization of Oil and Gas Reporting. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in the PV-10 and volumetric calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, year-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves are allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC Form 10K.

This release is effective for financial statements issued for fiscal years and interim periods beginning on or after January 1, 2010.

2. Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the 2008, 2007, and 2006 periods and are discussed below. Due to the loss from continuing operations in 2008 all stock options and restricted stock are antidilutive and there is no effect to diluted EPS.

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, 2008, 2007, and 2006 (in thousands, except per share amounts):

	2008			2007			2006		
	Loss from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) from continuing operations, and share Amounts	$ (257,130)	30,661	$ (8.39)	$ 152,588	29,984	$ 5.09	$ 151,074	29,265	$ 5.16
Dilutive Securities:									
Restricted Stock	--	--		--	218		--	169	
Stock Options	--	--		--	438		--	582	
Diluted EPS:									
Net Income (Loss) from continuing operations, and assumed share conversions	$ (257,130)	30,661	$ (8.39)	$ 152,588	30,640	$ 4.98	$ 151,074	30,016	$ 5.03

Options to purchase approximately 1.1 million shares at an average exercise price of $33.22 were outstanding at December 31, 2008, while options to purchase 1.4 million shares at an average exercise price of $28.47 were outstanding at December 31, 2007, and options to purchase 1.5 million shares at an average exercise price of $24.59 were outstanding at December 31, 2006. All of the 1.1 million stock options to purchase shares outstanding at December 31, 2008 were not included in the computation Diluted EPS for 2008, as they would be antidilutive given the net loss from continuing operations. Approximately 1.0 million stock options to purchase shares were not included in the computation of Diluted EPS for the each of the years ended December 31, 2007, and 2006, respectively, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. All of the 0.6 million shares of employee restricted stock outstanding at December 31, 2008 were not included in the computation Diluted EPS for 2008, as they would be antidilutive given the net loss from continuing operations. Employee restricted stock grants of 0.4 million shares and less than 0.3 million shares were not included in the computation of Diluted EPS for the years ended December 31, 2007 and 2006, respectively, because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period.

3. Provision (Benefit) for Income Taxes

Income (Loss) from continuing operations before taxes is as follows (in thousands):

	Year Ended December 31, 2008	2007	2006
Income (Loss) from Continuing Operations Before Income Taxes	$ (412,758)	$ 244,556	$ 248,308

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

	Year Ended December 31, 2008	2007	2006
Current:	$ 5,923	$ 6,902	$ 2,860
Deferred	(161,551)	85,066	94,374
Total	$ (155,628)	$ 91,968	$ 97,234

Current taxes are primarily U.S. Federal income taxes. The Company has no continuing operations in foreign jurisdictions.

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

	2008	2007	2006
Income taxes computed at U.S. statutory rate (35%)	$ (144,465)	$ 85,595	$ 86,908
State tax provisions (benefits), net of federal benefits	(11,985)	3,396	3,921
Cumulative impact of adjustments to net state income tax rate	---	---	1,547
Write-offs and valuation allowance of carryover tax assets	---	2,585	3,200
Other, net	822	392	1,658
Provision (benefit) for income taxes	$ (155,628)	$ 91,968	$ 97,234
Effective rate	37.7%	37.6%	39.2%

The primary upward adjustment in the effective tax rate above the U.S. statutory rate is the provision for state income taxes (computed net of the offsetting federal benefit), which was a credit of $12.0 million for 2008, and charges of $3.4 million and $3.9 million for 2007, and 2006, respectively. In 2007 and 2006, the company recorded write-offs and valuation allowances of $2.6 million and $3.2 million, respectively due to changes in the Company’s tax planning strategies.

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2008 and 2007 were as follows (in thousands):

	2008	2007
Current deferred tax assets:		
Alternative minimum tax credits	---	5,094
Unrealized stock compensation	---	2,403
Other	---	558
Total current deferred tax assets	$ ---	$ 8,055
Non-Current deferred tax assets:		
Federal net operating losses	$ 15,971	$ ---
Alternative minimum tax credits	14,509	---
Carryover items, net of valuation allowance	8,034	4,334
Unrealized stock compensation	4,399	1,294
Other	2,977	749
Total non-current deferred tax assets	$ 45,890	$ 6,377
Non-Current deferred tax liabilities:		
Oil and gas exploration and development costs	$ 175,108	$ 307,083

Other		1,681		1,597
Total deferred tax liabilities	$	176,789	$	308,680
Net Non-Current deferred tax liabilities	$	130,899	$	302,303

The total change in the deferred liability from 2007 to 2008 was a decrease of $131.9 million. This decrease is primarily attributable to a $132.0 million decrease in the deferred liability for oil and gas exploration and development costs. Book depletion of these assets exceeded tax depreciation, depletion and amortization primarily due to the non-cash ceiling write-down of oil and gas properties which is not recognized for tax.

Current deferred tax assets of $8.1 million at December 31, 2007 decreased to zero during 2008. Based on current oil and gas prices the Company does not anticipate generating regular taxable income in 2009. Therefore our tax assets are all classified as non-current as of December 31, 2008. Changes in market prices for oil and natural gas along with other economic and operational factors could result in a portion of the deferred tax asset to be realized within the next year.

Non-current deferred tax assets increased by $39.5 million, primarily due to a $16.0 million dollar increase for Federal income tax net operating losses, and an increase in the non-current alternative minimum tax (AMT) asset of $14.5 million, which includes an increase of $9.4 million in the total AMT asset and a reclass of the prior year $5.1 million AMT asset from current to non-current. Other increases included $3.7 million for other carryover items which are primarily state tax loss carryforwards, $3.1 million for unrealized stock compensation, and $2.2 million for other items.

The federal net operating losses will expire in 2027 and 2028 if not utilized in earlier periods. The other primary carryover item is $7.4 million for State of Louisiana net operating loss carryovers. These loss carryforwards are scheduled to expire between 2013 and 2023.

Unrealized stock compensation accounts for $4.4 million in deferred tax assets. These amounts are attributable to stock compensation expenses accrued for employee stock options and restricted stock that are not realized for income tax purposes until exercised (for stock options) or vested (for restricted stock). The actual tax deductions realized may be significantly different than the accrued amounts depending on the market value of the stock on the date of exercise or vesting.

There is also a deferred tax asset of $1.1 million for a capital loss carryforward which is fully offset by a valuation allowance. This carryover is scheduled to expire in 2010.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. In the 4th quarter of 2008 we recorded additional tax expense and increased other long-term liabilities by $0.3 million, which increased our total balance of our unrecognized tax benefits to $1.3 million. If recognized, these tax benefits would fully impact our effective tax rate.

We do not believe the total of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2008, we have accrued $0.3 million for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns from 1998 through 2003 and 2005 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

In the third quarter of 2007, we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company’s property disposition plans and increased income tax expense of $2.6 million in that period. Subsequently, all but $1.1 million of our capital loss carryforward assets have expired, and we continue to carry a valuation allowance for the full remaining balance.

4. Long-Term Debt

Our long-term debt as of December 31, 2008 and 2007, is as follows (in thousands):

	2008	2007
Bank Borrowings	$ 180,700	$ 187,000
7-5/8% senior notes due 2011	150,000	150,000
7-1/8% senior notes due 2017	250,000	250,000
Long-Term Debt	$ 580,700	$ 587,000

Bank Borrowings. At December 31, 2008 and 2007, we had borrowings of $180.7 million and $187.0 million, respectively, under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base at December 31, 2008 of $400.0 million and a commitment amount of $350.0 million, based entirely on assets from continuing operations, and expires in October 2011. The interest rate is either (a) the lead bank's prime rate (3.25% at December 31, 2008) 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. In April 2007, we increased the borrowing base to $350.0 million from $250.0 million; and effective November 2007, we further increased it to $400.0 million. In September 2007, we increased the commitment amount under the borrowing base to $350.0 million from $250.0 million. In October 2008, our lenders reaffirmed our borrowing base and commitment amount as part of their normal recurring borrowing base review. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred an additional $0.3 million of debt issuance costs related to the increase of the commitment amount in 2007, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011. 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 natural gas properties. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in May 2009.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $8.6 million in 2008, $6.1 million in 2007, and $1.5 million in 2006. The amount of commitment fees included in interest expense, net was $0.5 million in 2008 and 2007 and $0.6 million in 2006.

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

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $12.0 million in 2008 and 2007, and $11.9 million in 2006.

Senior Subordinated Notes Due 2012. These notes consisted of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002 and were scheduled to mature on May 1, 2012. Interest on these notes was payable semiannually on May 1 and November 1. As of June 18, 2007, we redeemed all $200.0 million of these notes. In the second quarter of 2007, we recorded a charge of $12.8 million related to the redemption of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statement of income. The costs were comprised of approximately $9.4 million of premium paid to redeem the notes, and $3.4 million to write-off unamortized debt issuance costs.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs, totaled $8.9 million in 2007 and $19.2 million in 2006.

Senior Notes Due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. In addition, prior to June 1, 2010, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.125% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Debt issuance costs” on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $18.1 million and $10.6 million for the year ended December 31, 2008 and 2007, respectfully.

The maturities on our long-term debt are $0 for 2009 and 2010, $331 million for 2011, and $250 million thereafter.

We have capitalized interest on our unproved properties in the amount of $8.0 million, $9.5 million, and $9.2 million, in 2008, 2007, and 2006, respectively.

5. Commitments and Contingencies

Rental and lease expenses which were included in “General and administrative, net” on our accompanying consolidated statements of income were $3.2 million in 2008, $3.7 million in 2007, and $2.7 million in 2006. Rental and lease expenses which were included in “Lease operating cost” on our accompanying consolidated statements of income were $8.6 million in 2008, $6.7 million in 2007, and $3.6 million in 2006. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $8.0 million for 2009, $7.0 million for 2010, $5.9 million for 2011, $6.0 million for 2012, $6.2 million for 2013, and $7.5 million thereafter or $40.6 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 which is a ten year lease and expires in 2015.

In the ordinary course of business, we have entered into agreements with drilling contractors, seismic providers, and tubing and pipe inventory commitments. The remaining commitments at December 31, 2008 for these services and materials totaled $8.1 million for 2009.

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 natural gas wells. In management’s opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders' Equity

Stock-Based Compensation Plans. We have three stock option plans that awards are currently granted under, the 2005 Stock Compensation Plan, which was adopted by our Board of Directors in March 2005 and was approved by shareholders at the 2005 annual meeting of shareholders, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants, other than stock option reload grants under the 2001 plan, will be made under the 2001 Omnibus Stock Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the 2005 Stock Compensation Plan, although options remain outstanding under both plans and are accordingly included in the tables below. In addition, we have an employee stock purchase plan and an employee stock ownership plan.

Under the 2005 plan, stock options and other equity based awards may be granted to employees, directors, and consultants, with directors only eligible to receive restricted awards. Under the 2001 plan, stock options and other equity based awards may be granted to employees. Under the 1990 non-qualified plan, non-employee members of our Board of Directors were automatically granted options to purchase shares of common stock on a formula basis. All three plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested in various terms ranging from three years to five years, and stock options become exercisable in various terms ranging from one year to five years. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under these plans also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying Statement of Stockholders' Equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. Through May 31, 2006, the plan year was from June 1 to the following May 31. A transition period from June 1 to December 31 was used during the second half of 2006 and a new calendar year plan, from January 1 to December 31, began in 2007. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary, within IRS limitations and plan rules, 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 through the plan year, for plan years ending on or before May 31, 2007). Under this plan for the last three years, we have issued 25,645 shares at a price of $36.83 in 2008, 17,678 shares at a price of $35.00 in 2007, and 22,425 shares at a price range of $29.84 to $32.80 in 2006 and registered 200,000 new shares in 2008. As of December 31, 2008, 208,031 shares remained available for issuance under this plan.

As a result of adopting SFAS No. 123R on January 1, 2006, our income from continuing operations before income taxes, income from continuing operations, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. These benefits were $4.7 million, $1.8 million, and $3.3 million for the years ended December 31, 2008, 2007, and 2006 respectively. The benefit for the year ended December 31, 2008 that was not recognized in the financial statements, as these benefits had not been realized through the estimated alternative minimum tax calculation, was $3.2 million and the benefit for the year ended December 31, 2007, that was not recognized in the financial statements as these benefits had not been realized due to a tax net operating loss position for this period, was $1.2 million.

Net cash proceeds from the exercise of stock options were $8.3 million, $3.2 million, and $11.8 million for the years ended December 31, 2008, 2007, and 2006 respectively. The actual income tax benefit from stock option exercises was $4.1 million, $1.9 million, and $4.8 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in “General and Administrative, net” in the accompanying consolidated statements of income, and was $10.6 million, $9.4 million, and $6.3 million for the years ended December 31, 2008, 2007, and 2006, respectively. Stock compensation recorded in “Lease operating cost” was $0.6 million, $0.5 million, and $0.3 million for the years ended December 31, 2008, 2007, and 2006, respectively. We also capitalized $4.5 million, $4.2 million, and $3.4 million of stock compensation in 2008, 2007, and 2006, respectively.

Our shares available for future grant under our stock compensation plans were 967,906 at December 31, 2008. Each stock option granted reduces the aforementioned total by one share, while each restricted stock grant reduces the shares available for future grant by 1.44 shares.

Stock Options. We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods:

	Years Ended December 31,		
	2008	2007	2006
Dividend yield	0%	0%	0%
Expected volatility	39.5%	38.5%	39.3%
Risk-free interest rate	2.4%	4.7%	4.8%
Expected life of options (in years)	4.1	6.0	4.8
Weighted-average grant-date fair value	$ 15.26	$ 19.61	$ 18.03

The expected term for grants issued during 2008 has been based on an analysis of historical employee exercise behavior and considered all relevant factors including expected future employee exercise behavior. The expected term for grants issued prior to 2008 was calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility, and based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our 2008 stock option grants, which is an increase from the four-year period used to estimate expected volatility for grants prior to 2008.

At December 31, 2008, $2.0 million of unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 1.1 years.

The following table represents stock option activity for the years ended December 31, 2008, 2007 and 2006:

	2008		2007		2006	
	Shares	Wtd Avg. Exer. Price	Shares	Wtd, Avg Exer. Price	Shares	Wtd. Avg Exer. Price
Options outstanding, beginning of period	1,449,240	$ 28.47	1,549,140	$ 24.59	2,118,179	$ 21.28
Options granted	216,315	$ 46.37	201,691	$ 43.40	234,110	$ 45.73
Options canceled	(44,289)	$ 34.69	(41,800)	$ 37.15	(51,739)	$ 22.25
Options exercised1	(501,797)	$ 24.96	(259,791)	$ 18.13	(751,410)	$ 22.02
Options outstanding, end of period	1,119,469	$ 33.22	1,449,240	$ 28.47	1,549,140	$ 24.59
Options exercisable, end	649,714	$ 26.41	967,429	$ 25.70	884,876	$ 22.60

of period

1 The plans allow for the use of a “stock swap” in lieu of a cash exercise for options, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid “stock swap.” Options issued under a “stock swap” also include a reload feature where additional options are granted at the then current market price when mature shares of Swift stock are used to satisfy the exercise price of an existing stock option grant. The terms of the plans provide that the mature shares delivered, as full or partial payment in a “stock swap”, shall again be available for awards under the plans. In 2008, 2007 and 2006, respectively, 81,515, 19,191 and 98,581 mature shares were delivered in “stock swap” transactions, which resulted in the issuance of an equal number of reload option grants.

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at December 31, 2008 was $1.0 million and 5.2 years and $1.0 million and 4.0 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2008 was $13.7 million.

The following table summarizes information about stock options outstanding at December 31, 2008:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/08	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/08	Wtd. Avg. Exercise Price
$ 6.00 to $24.99	332,695	3.9	$ 14.75	311,797	$ 14.45
$25.00 to $44.99	640,843	6.5	$ 38.43	263,868	$ 33.88
$45.00 to $65.00	145,931	2.2	$ 52.44	74,049	$ 50.16
$ 6.00 to $65.00	1,119,469	5.2	$ 33.22	649,714	$ 26.41

Restricted Stock. In 2008, 2007 and 2006, the Company issued 314,440, 329,290 and 324,640 shares, respectively, of restricted stock to employees, consultants, and directors. These shares vest over a three-year to five-year period and remain subject to forfeiture if vesting conditions are not met. The fair value of these shares when issued was approximately $44 per share in 2008 and $43 per share in 2007 and 2006.

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2008, we have unrecognized compensation expense of approximately $11.9 million associated with these awards which are expected to be recognized over a weighted-average period of 1.4 years. The total fair value of shares vested during the year ended December 31, 2008 was $11.3 million.

The following is a summary of our restricted stock issued to employees, consultants, and directors under these plans as of December 31, 2008, 2007, and 2006:

	2008		2007		2006	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg.Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	596,590	$ 41.60	503,184	$ 40.04	236,950	$ 34.79
Restricted shares granted	314,440	$ 43.61	329,290	$ 43.17	324,640	$ 43.21
Restricted shares canceled	(49,859)	$ 42.65	(47,595)	$ 39.63	(22,630)	$ 38.01
Restricted shares vested	(274,846)	$ 41.18	(188,289)	$ 40.05	(35,776)	$ 24.57
Restricted shares outstanding, end of period	586,325	$ 42.78	596,590	$ 41.60	503,184	$ 40.04

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan ("ESOP") effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a five-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2008, 2007, and 2006, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the year ended December 31, 2008 and $0.4 million for the years ended December 31, 2007 and 2006, and were all made in common stock, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The shares of common stock contributed to the ESOP plan totaled 11,898, 9,218, and 8,927 shares for the 2008, 2007, and 2006 contributions, respectively.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $1.5 million for 2008, $1.3 million for 2007, and $1.0 million for 2006, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The contributions in 2008, 2007, and 2006 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 82,125, 29,934, and 23,890 shares for the 2008, 2007, and 2006 contributions, respectively.

Treasury Shares. 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, 2008, 467,884 shares remain in treasury (net of 572,657 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $10.4 million and are included in "Treasury stock held, at cost" on the accompanying consolidated balance sheets.

Shareholder Rights Plan. Our Rights Agreement was initially adopted by the Board of Directors in 1997 for a ten-year term. The Board of Directors renewed and extended the Rights Agreement for an additional ten-year term on December 21, 2006. Pursuant to the Rights Agreement as amended, for each share of Swift Energy common stock a holder has the right to purchase one one-thousandth of a share of Swift Energy preferred stock for $250 upon the occurrence of certain events triggered when a person or entity purchases 15% or more beneficial ownership of Swift Energy's outstanding common stock. The rights are not exercisable by such 15% or more beneficial owner.

7. Related-Party Transactions

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.7 million to Tec-Com for such services pursuant to the terms of the contract in 2008, $0.6 million in 2007 and $0.5 million in 2006. The contract was renewed on June 30, 2007 on substantially the same terms as the previous contract and expires June 30, 2010. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee's charter.

8. Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations for 2007 and 2008 have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. In connection with the sale of our last permit, a third-party has brought suit against Swift Energy for breach of contract related to obtaining their consent for the transfer of the permit. The third-party has also brought suit against the New Zealand Ministry of Economic Development which challenges the transfer of this permit from Swift Energy to the purchaser. We have evaluated the situation and believe we have not met the revenue recognition criteria at this time for the permit sale, and have deferred the potential gain on this property sale pending the outcome of this litigation.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets. During the fourth quarter of 2007 and the full year of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded non-cash asset write-downs of $143.2 million and $3.6 million, respectively, related to these assets. These write-downs are recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying consolidated statements of income.

The book value of our remaining New Zealand permit is approximately $0.6 million at December 31, 2008.

The following table summarizes the amounts included in income (loss) from discontinued operations for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported in discontinued operations (in thousands except per share amounts):

	2008	2007	2006
Oil and gas sales	$ 14,675	$ 42,394	$ 64,039
Other revenues	832	1,221	862
Total revenues	15,507	43,615	64,901
Depreciation, depletion, and amortization	4,857	23,147	30,051
Other operating expenses	10,750	22,491	20,872
Non-cash write-down of property and equipment	3,572	143,152	---
Total expenses	19,179	188,790	50,923
Income (loss) from discontinued operations before income taxes	(3,672)	(145,175)	13,978
Income tax expense (benefit)	(312)	(13,874)	3,487
Income (loss) from discontinued operations, net of taxes	$ (3,360)	$ (131,301)	$ 10,491
Earnings per common share from discontinued operations-diluted	$ (0.11)	$ (4.29)	$ 0.35
Annual sales volumes (MBoe)	415	1,387	2,252
Total assets	$ 564	$ 110,585	$ 235,997
Cash flow provided by operating activities	$ 6,039	$ 25,620	$ 41,680
Capital expenditures	$ 1,273	$ 9,466	$ 56,707

Our capitalized general and administrative expenses were immaterial in 2008 and were $4.2 million and $4.1 million in 2007 and 2006, respectively.

Total income taxes differed from the amount computed by applying the statutory income tax rate to income from discontinued operations. The sources of these differences are as follows (in thousands):

	2008	2007	2006
Income (loss) before tax from discontinued operations	$ (3,672)	$ (145,175)	$ 13,978
Income taxes computed at U.S. statutory rate (35%)	$ (1,285)	$ (50,811)	$ 4,892
Effect of foreign operations	973	6,336	(293)
Currency exchange impact on foreign tax calculation	---	(1,659)	(1,346)
Valuation allowance	---	33,502	---
Other	---	(1,242)	234
Total income tax expense related to discontinued operations	$ (312)	$ (13,874)	$ 3,487
Effective tax rate	8.5%	9.6%	24.9%

There were no significant net deferred assets (liabilities) associated with assets held for sale at December 31, 2008 and 2007

The 2007 non-cash write-down of properties held for sale resulted in an estimated net deferred tax asset balance of $33.5 million, calculated using the New Zealand tax rate of 30%. This estimated net asset was attributable to New Zealand tax loss carryovers that are denominated in New Zealand dollars. As of December 31, 2008, the U.S. dollar value of the deferred asset was $25.8 million. The decrease is primarily attributable to a decrease in the New Zealand dollar exchange rate. As of December 31, 2007 and December 31, 2008, management assessed that the probability of generating additional taxable income to utilize these loss carryovers was not more likely than not. Since the Company's book value of this deferred tax asset is zero, no adjustments have been made to the provision for income tax from discontinued operations for the change in the gross deferred tax asset value.

The following presents the main classes of assets and liabilities associated with the New Zealand operations that were held for sale as of December 31, 2008 and 2007 (in thousands):

	2008	2007
ASSETS		
Property and equipment, net	$ 564	$ 96,549
Total Current assets held for sale	$ 564	$ 96,549
LIABILITIES		
Asset retirement obligation	$ ---	$ 8,066
Total Current liabilities associated with assets held for sale	$ ---	$ 8,066

9. Acquisitions and Dispositions

In August 2008, we announced the acquisition of oil and natural gas interests in South Texas from Crimson Energy Partners, L.P. a privately held company. The property interests are located in the Briscoe "A" lease in Dimmit County. Including an accrual of $0.6 million for purchase price adjustment reductions, we paid approximately $45.9 million in cash for these interests. After taking into account internal acquisition costs of $1.5 million, our total cost was $47.4 million. We allocated $44.0 million of the acquisition price to "Proved Properties," $3.4 million to "Unproved Properties," and recorded a liability for $0.2 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying consolidated statement of income from the date of acquisition forward, and due to the short time period, are not material to our 2008 results.

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. The property interests are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmit County, and the Las Tiendas field in Webb County. We paid approximately $248.2 million in cash for these interests including purchase price adjustments. After taking into account internal acquisition costs of $2.5 million, our total cost was $250.7 million. We allocated $241.8 million of the acquisition price to "Proved Properties," $8.9 million to "Unproved Properties," and recorded a liability for $0.6 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying consolidated statement of income from the date of acquisition forward; however, given that the acquisitions closed in the fourth quarter of 2007, these amounts were not material to our full year 2007 results.

In December 2006, we acquired additional interests in our Lake Washington field. We paid approximately $20.0 million in cash for these interests. After taking into account internal acquisition costs of $0.4 million, our total cost was $20.4 million. We allocated $17.9 million of the acquisition price to "Proved Properties," $2.5 million to "Unproved Properties," and recorded a liability for $0.8 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from this acquisition have been included in our accompanying consolidated statements of income from the date of acquisition forward; however, given the acquisition closed in December 2006, these amounts were not material to our full year 2006 results.

In October 2006, we acquired interests in five South Louisiana fields. The property interests are located in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We paid approximately $167.9 million in cash for these interests. After taking into account internal acquisition costs of $4.0 million, our total cost was $171.9 million. We allocated $143.1 million of the acquisition price to "Proved Properties," $28.8 million to "Unproved Properties," and recorded a liability for $11.5 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward; however, given the acquisitions closed in the fourth quarter of 2006, these amounts were not material to our full year 2006 results.

In April 2006, we sold our minority interest in the Brookeland natural gas processing plant for approximately $20.3 million in cash. Under the "full-cost" method of accounting for oil and natural gas property and equipment costs, the proceeds of this sale were applied against our oil and natural gas properties and equipment balance, and no gain or loss was recognized on this transaction.

10. Fair Value Measurements

We adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements," on January 1, 2008. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. The adoption of this statement did not have a material impact on our financial position or results of operations.

The following tables present our assets that are measured at fair value on a recurring basis during the year ended December 31, 2008 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

Assets	Fair Value Measurements at December 31, 2008			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money Market Funds	$ 1.3	$ 1.3	$ ---	$ ---

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the three months ended December 31, 2008 (in millions):

Fair Value Reconciliation at December 31, 2008 – QTD	Hedging Contracts
Balance as of September 30, 2008	$ 9.4
Total gains (losses) (realized or unrealized):	
Included in earnings	28.8
Included in other comprehensive income	(7.4)
Purchases, issuances and settlements	(30.8)
Balance as of December 31, 2008	$ ---

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the year ended December 31, 2008 (in millions):

Fair Value Reconciliation at December 31, 2008 – YTD	Hedging Contracts

Balance as of December 31, 2007	$	0.3
Total gains (losses) (realized or unrealized):		
Included in earnings		26.1
Included in other comprehensive income		0.7
Purchases, issuances and settlements		(27.1)
Balance as of December 31, 2008	$	---

11. Condensed Consolidating Financial Information

In December 2006, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012, which were redeemed in June 2007, and for our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 1). As part of this restructuring these indentures were amended so that both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. The co-obligations on our Notes due 2011 are full and unconditional and are joint and several. Prior to this restructure, Swift Energy Company was the sole obligor. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	December 31, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 77,323	$ 763	$ ---	$ 78,086
Property and equipment	---	1,431,447	---	---	1,431,447
Investment in subsidiaries (equity method)	600,877	---	529,209	(1,130,086)	---
Other assets	---	7,755	71,089	(71,089)	7,755
Total assets	$ 600,877	$ 1,516,525	$ 601,061	$ (1,201,175)	$ 1,517,288
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 153,315	$ 184	$ ---	$ 153,499
Long-term liabilities	---	834,001	---	(71,089)	762,912
Stockholders' equity	600,877	529,209	600,877	(1,130,086)	600,877
Total liabilities and stockholders' equity	$ 600,877	$ 1,516,525	$ 601,061	$ (1,201,175)	$ 1,517,288

(in thousands)	December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 89,513	$ 110,437	$ ---	$ 199,950
Property and equipment	---	1,760,195	---	---	1,760,195
Investment in subsidiaries (equity method)	836,054	---	760,158	(1,596,212)	---

Other assets	---	28,828	---	(19,922)	8,906
Total assets	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 195,542	$ 34,541	$ (19,922)	$ 210,161
Long-term liabilities	---	922,836	---	---	922,836
Stockholders' equity	836,054	760,158	836,054	(1,596,212)	836,054
Total liabilities and stockholders' equity	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051

(in thousands)	December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 75,270	$ 8,513	$ ---	$ 83,783
Property and equipment	---	1,239,722	---	---	1,239,722
Investment in subsidiaries (equity method)	797,917	---	590,720	(1,388,637)	---
Other assets	---	42,519	253,085	(33,427)	262,177
Total assets	$ 797,917	$ 1,357,511	$ 852,318	$ (1,422,064)	$ 1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 137,016	$ 8,455	$ ---	$ 145,471
Long-term liabilities	---	629,775	45,946	(33,427)	642,294
Stockholders' equity	797,917	590,720	797,917	(1,388,637)	797,917
Total liabilities and stockholders' equity	$ 797,917	$ 1,357,511	$ 852,318	$ (1,422,064)	$ 1,585,682

Condensed Consolidating Statements of Income

(in thousands)	Year Ended December 31, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 820,815	$ ---	$ ---	$ 820,815
Expenses	---	1,233,573	---	---	1,233,573
Income (Loss) before the following:	---	(412,758)	---	---	(412,758)
Equity in net earnings of subsidiaries	(260,490)	---	(257,130)	517,620	---
Income (Loss) from continuing operations, before income taxes	(260,490)	(412,758)	(257,130)	517,620	(412,758)
Income tax provision (benefit)	---	(155,628)	---	---	(155,628)
Income (Loss) from continuing operations	(260,490)	(257,130)	(257,130)	517,620	(257,130)
Loss from discontinued operations, net of taxes	---	---	(3,360)	---	(3,360)
Net income (loss)	$ (260,490)	$ (257,130)	$ (260,490)	$ 517,620	$ (260,490)

(in thousands)	Year Ended December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 654,121	$ ---	$ ---	$ 654,121
Expenses	---	409,565	---	---	409,565

Income (loss) before the following:	---	244,556	---	---	244,556
Equity in net earnings of subsidiaries	21,287	---	152,588	(173,875)	---
Income from continuing operations, before income taxes	21,287	244,556	152,588	(173,875)	244,556
Income tax provision	---	91,968	---	---	91,968
Income from continuing operations	21,287	152,588	152,588	(173,875)	152,588
Loss from discontinued operations, net of taxes	---	---	(131,301)	---	(131,301)
Net income	$ 21,287	$ 152,588	$ 21,287	$ (173,875)	$ 21,287

(in thousands)	Year Ended December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 550,836	$ ---	$ ---	$ 550,836
Expenses	---	302,528	---	---	302,528
Income (loss) before the following:	---	248,308	---	---	248,308
Equity in net earnings of subsidiaries	161,565	---	151,074	(312,639)	---
Income from continuing operations, before income taxes	161,565	248,308	151,074	(312,639)	248,308
Income tax provision	---	97,234	---	---	97,234
Income from continuing operations	161,565	151,074	151,074	(312,639)	151,074
Income from discontinued operations, net of taxes	---	---	10,491	---	10,491
Net income	$ 161,565	$ 151,074	$ 161,565	$ (312,639)	$ 161,565

Condensed Consolidating Statements of Cash Flow

(in thousands)	Year Ended December 31, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 582,027	$ 6,039	$ ---	$ 588,066
Cash flow from investing activities	---	(582,863)	80,504	(91,790)	(594,149)
Cash flow from financing activities	---	743	(91,790)	91,790	743
Net decrease in cash	---	(93)	(5,247)	---	(5,340)
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 87	$ 196	$ ---	$ 283

(in thousands)	Year Ended December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 442,282	$ 25,620	$ ---	$ 467,902
Cash flow from investing activities	---	(636,501)	(7,827)	(13,358)	(657,686)
Cash flow from financing activities	---	194,349	(13,358)	13,358	194,349
Net increase in cash	---	130	4,435	---	4,565
Cash, beginning of period	---	50	1,008	---	1,058
Cash, end of period	$ ---	$ 180	$ 5,443	$ ---	$ 5,623

(in thousands)	Year Ended December 31, 2006				
				Eliminations	

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries		Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 383,241	$ 41,680	$ ---	$ 424,921
Cash flow from investing activities	---	(474,781)	(59,881)	11,115	(523,547)
Cash flow from financing activities	---	46,679	11,115	(11,115)	46,679
Net decrease in cash	---	(44,861)	(7,086)	---	(51,947)
Cash, beginning of period	---	44,911	8,094	---	53,005
Cash, end of period	$ ---	$ 50	$ 1,008	$ ---	$ 1,058

Supplementary Information

Swift Energy Company and Subsidiaries
Oil and Gas Operations (Unaudited)

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

	Total	Domestic	Discontinued Operations
December 31, 2008:			
Proved oil and gas properties	$ 3,270,159	$ 3,270,159	$ ---
Unproved oil and gas properties	91,252	91,252	---
	3,361,411	3,361,411	---
Accumulated depreciation, depletion, and amortization	(1,954,222)	(1,954,222)	---
Net capitalized costs	$ 1,407,189	$ 1,407,189	$ ---
December 31, 2007:			
Proved oil and gas properties	$ 2,951,712	$ 2,610,469	$ 341,243
Unproved oil and gas properties	107,095	106,643	452
	3,058,807	2,717,112	341,695
Accumulated depreciation, depletion, and amortization	(1,234,401)	(981,449)	(252,952)
Net capitalized costs	$ 1,824,406	$ 1,735,663	$ 88,743

Of the $91.3 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2008, excluded from the amortizable base, $45.7 million was incurred in 2008, $21.6 million was incurred in 2007, $17.5 million was incurred in 2006, and $6.5 million was incurred in prior years. We evaluate the majority of these unproved costs within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved properties as of December 31, 2008, 2007, and 2006.

Costs Incurred. The following table sets forth costs incurred related to our oil and natural gas operations (in thousands):

	Year Ended December 31, 2008		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 47,245	$ 47,245	$ --
Lease acquisitions and prospect costs1	72,513	71,240	1,273
Exploration	47,832	47,832	---
Development 2	477,982	477,982	---
Total acquisition, exploration, and development 3, 4	$ 645,572	$ 644,299	$ 1,273

	Year Ended December 31, 2007		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 253,573	$ 253,573	$ --
Lease acquisitions and prospect costs1	62,380	56,901	5,479
Exploration	65,815	65,815	---
Development 2	330,866	326,879	3,987
Total acquisition, exploration, and development 3, 4	$ 712,634	$ 703,168	$ 9,466

	Year Ended December 31, 2006		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 212,499	$ 212,499	$ --
Lease acquisitions and prospect costs1	79,183	68,594	10,589
Exploration	29,286	13,225	16,061
Development 2	261,143	231,086	30,057
Total acquisition, exploration, and development 3, 4	$ 582,111	$ 525,404	$ 56,707

1 These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2008, 2007, and 2006 were $56.7 million, $50.2 million, and $70.5 million, respectively. Domestic costs for seismic data acquisition, included above, were $12.4 million, 11.6 million, and $23.1 million in 2008, 2007, and 2006, respectively. New Zealand costs for seismic data acquisition, included above were $0.5 million in 2007 and $3.8 million in 2006.

2 Facility construction costs and capital costs have been included in development costs, and totaled $48.2 million, $71.3 million, and $16.5 million for the years ended December 31, 2008, 2007, and 2006, respectively.

3 Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $30.1 million, $30.6 million, and $28.3 million in 2008, 2007, and 2006, respectively. In addition, the total includes $8.0 million, $9.5 million, and $9.2 million in 2008, 2007, and 2006, respectively, of capitalized interest on unproved properties.

4 Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2008, 2007, and 2006.

Results of Operations (in thousands).

	Year Ended December 31, 2008		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 808,534	$ 793,859	$ 14,675
Lease operating cost	(111,220)	(104,874)	(6,346)
Severance and other taxes	(81,376)	(80,403)	(973)
Depreciation, depletion, and amortization	(227,145)	(222,288)	(4,857)
Accretion of asset retirement obligation	(2,019)	(1,958)	(61)
Write-down of oil and gas properties	(757,870)	(754,298)	(3,572)
	(371,096)	(369,962)	(1,134)
Benefit for income taxes	139,554	139,476	78
Results of producing activities	$ (231,542)	$ (230,486)	$ (1,056)
Amortization per physical unit of production (equivalent Bbl of oil)	$ 21.71	$ 22.12	$ 11.71

Year Ended December 31, 2007

	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 695,250	$ 652,856	$ 42,394
Lease operating cost	(84,670)	(70,893)	(13,777)
Severance and other taxes	(76,647)	(73,813)	(2,834)
Depreciation, depletion, and amortization	(208,757)	(186,086)	(22,671)
Accretion of asset retirement obligation	(1,625)	(1,437)	(188)
Write-down of oil and gas properties	(143,152)	---	(143,152)
	180,399	320,627	(140,228)
(Provision) benefit for income taxes	(108,056)	(121,518)	13,462
Results of producing activities	$ 72,343	$ 199,109	$ (126,766)
Amortization per physical unit of production (equivalent Bbl of oil)	$ 17.39	$ 17.53	$ 16.34

	Year Ended December 31, 2006		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 601,552	$ 537,513	$ 64,039
Lease operating cost	(62,475)	(49,948)	(12,527)
Severance and other taxes	(65,452)	(61,235)	(4,217)
Depreciation, depletion and amortization	(166,518)	(136,826)	(29,692)
Accretion of asset retirement obligation	(1,035)	(885)	(150)
	306,072	288,619	17,453
Provision for income taxes	(117,493)	(113,139)	(4,354)
Results of producing activities	$ 188,579	$ 175,480	$ 13,099
Amortization per physical unit of production (equivalent Bbl of oil)	$ 14.23	$ 14.48	$ 13.18

These results of operations do not include the gains from our hedging activities of $26.1 million, $0.2 million and 4.0 million for 2008, 2007 and 2006, respectively. Our lease operating costs per Boe produced were $10.44 in 2008, $6.68 in 2007, and $5.29 in 2006.

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

Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. (“Gruy”), independent petroleum consultants. Gruy has audited 97% of our 2008 domestic proved reserves and 100% of our domestic proved reserves for 2007 and 2006, and 100% of our New Zealand proved reserves for 2007 and 2006. 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 us. Gruy’s report dated February 3, 2009, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2008, and includes assumptions and references to the definitions that serve as the basis for the audit of proved reserves and future net cash flows.

Estimates of Proved Reserves	Total		Domestic		Discontinued Operations	
	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, 2005	287,473,150	79,053,056	225,274,807	69,783,276	62,198,343	9,269,779
Revisions of previous	(33,631,025)	3,127,635	(34,542,219)	3,135,885	911,194	(8,250)

estimates1						
Purchases of minerals in place	60,187,095	2,922,553	60,187,095	2,922,553	---	---
Sales of minerals in place	(6,122,283)	(708,691)	(6,122,283)	(708,691)	---	---
Extensions, discoveries, and other additions	39,012,428	5,627,297	38,466,980	5,512,795	545,448	114,502
Production	(22,787,948)	(7,902,766)	(13,603,589)	(7,181,287)	(9,184,359)	(721,479)
Proved reserves as of December 31, 2006	324,131,417	82,119,084	269,660,791	73,464,531	54,470,626	8,654,552
Revisions of previous estimates1	14,512,097	(2,227,517)	12,851,831	(1,947,699)	1,660,266	(279,818)
Purchases of minerals in place	37,748,518	6,571,426	37,748,518	6,571,426	---	---
Sales of minerals in place	---	---	---	---	---	---
Extensions, discoveries, and other additions	40,319,284	6,212,888	40,319,284	6,212,889	---	---
Production	(22,697,180)	(8,221,082)	(16,782,312)	(7,819,536)	(5,914,868)	(401,546)
Proved reserves as of December 31, 2007	394,014,136	84,454,799	343,798,112	76,481,611	50,216,024	7,973,188
Revisions of previous estimates1	(42,734,480)	(6,868,451)	(42,734,480)	(6,868,451)	---	---
Purchases of minerals in place	3,193,519	458,942	3,193,519	458,942	---	---
Sales of minerals in place	(48,382,504)	(7,863,827)	---	---	(48,382,504)	(7,863,827)
Extensions, discoveries, and other additions	8,626,050	4,269,906	8,626,050	4,269,906	---	---
Production	(22,336,764)	(6,740,904)	(20,503,244)	(6,631,543)	(1,833,520)	(109,361)

Proved reserves as of December 31, 2008	292,379,957	67,710,465	292,379,957	67,710,465	---	---
Proved developed reserves: 2						
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298,324	26,633,443	2,691,497
December 31, 2006	151,276,834	34,956,469	133,815,108	33,345,567	17,461,726	1,610,902
December 31, 2007	187,152,308	36,752,529	172,973,952	35,547,583	14,178,356	1,204,946
December 31, 2008	172,214,540	33,411,083	172,214,540	33,411,083	---	---

1 Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2008, were based upon prices in effect at year-end. We did not have any outstanding derivative instruments at year-end 2008 covering 2009 production that would affect prices used in these calculations. At December 31, 2008, we did not have any reserves in New Zealand. The weighted average of 2008 year-end prices for domestic operations were $4.96 per Mcf of natural gas, $44.09 per barrel of oil, and $25.39 per barrel of NGL, respectively. This compares to $6.19, $6.65, and $3.08 per Mcf of natural gas, $93.24, $93.24, and $93.20 per barrel of oil, and $54.63, $56.28 and $36.98 per barrel of NGL, respectively, as of December 31, 2007, for total, domestic, and discontinued operations. The weighted average of 2006 year-end prices for total, domestic, and discontinued operations were $5.46, $5.84, and $3.59 per Mcf of natural gas, $60.41, $60.07, and $63.51 per barrel of oil, and $30.93, $31.54 and $26.84 per barrel of NGL, respectfully.

2 At December 31, 2008, 53% of our total reserves were proved developed, compared to 45% at December 31, 2007, and 44% at December 31, 2006. At December 31, 2008, 53% of our domestic reserves were proved developed, compared to 48% at December 31, 2007, and 47% at December 31, 2006. At December 31, 2007, 22% of our New Zealand reserves were proved developed, compared to 25% at December 31, 2006.

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

	Year Ended December 31, 2008		
	Total	Domestic	Discontinued Operations
Future gross revenues	$ 4,099,878	$ 4,099,878	$ ---
Future production costs	(1,115,986)	(1,115,986)	---
Future development costs	(933,197)	(933,197)	---
Future net cash flows before income taxes	2,050,694	2,050,694	---
Future income taxes	(454,675)	(454,675)	---
Future net cash flows after income taxes	1,596,019	1,596,019	---
Discount at 10% per annum	(563,015)	(563,015)	---
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 1,033,004	$ 1,033,004	$ ---

	Year Ended December 31, 2007		
	Total	Domestic	Discontinued Operations
Future gross revenues	$ 9,547,840	$ 8,745,424	$ 802,416
Future production costs	(2,184,206)	(1,814,660)	(369,546)
Future development costs	(1,220,492)	(1,111,864)	(108,628)
Future net cash flows before income taxes	6,143,142	5,818,900	324,242
Future income taxes	(1,867,588)	(1,856,143)	(11,445)
Future net cash flows after income taxes	4,275,554	3,962,757	312,797

Discount at 10% per annum	(1,639,111)	(1,422,677)	(216,434)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 2,636,443	$ 2,540,080	$ 96,363

	Year Ended December 31, 2006		
	Total	Domestic	Discontinued Operations
Future gross revenues	$ 6,341,395	$ 5,659,085	$ 682,310
Future production costs	(1,393,634)	(1,167,117)	(226,517)
Future development costs	(935,004)	(886,843)	(48,161)
Future net cash flows before income taxes	4,012,757	3,605,125	407,632
Future income taxes	(1,187,859)	(1,137,617)	(50,242)
Future net cash flows after income taxes	2,824,898	2,467,508	357,390
Discount at 10% per annum	(956,238)	(835,593)	(120,645)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 1,868,660	$ 1,631,915	$ 236,745

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 natural 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 natural gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and natural gas prices for each period. At year-end 2008 we did not have any derivative instruments covering 2009 production. As such, they did not affect prices used in these calculations. Subsequent changes to such year-end oil and natural 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 natural 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 natural 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 (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Beginning balance	$ 2,636,443	$ 1,868,660	$ 2,159,369
Revisions to reserves proved in prior years--			
Net changes in prices, and production costs	(2,020,645)	1,259,492	(658,283)
Net changes in future development costs	(36,286)	(227,032)	(166,891)
Net changes due to revisions in quantity estimates	(229,290)	7,013	(60,714)
Accretion of discount	384,847	266,852	314,345
Other	(321,458)	(337,698)	(98,479)
Total revisions	(2,222,831)	968,627	(670,022)
New field discoveries and extensions, net of future production and development costs	91,414	305,843	212,629

Purchases of minerals in place	12,160	209,369	289,339
Sales of minerals in place	(90,148)	---	(20,378)
Sales of oil and gas produced, net of production costs	(616,272)	(533,934)	(473,625)
Previously estimated development costs incurred	290,337	230,046	187,134
Net change in income taxes	931,901	(412,168)	184,214
Net change in standardized measure of discounted future net cash flows	(1,603,439)	767,783	(290,709)
Ending balance	$ 1,033,004	$ 2,636,443	$ 1,868,660

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2008 and 2007 (in thousands, except per share data):

	Revenues	Income (Loss) from Continuing Operations Before Income Taxes	Income (Loss) from Continuing Operations	Income (Loss) from Discontinued Operations	Basic EPS from Continuing Operations	Diluted EPS from Continuing Operations
2008:						
First	$ 198,960	$ 78,842	$ 49,835	$ (1,474)	$ 1.64	$ 1.61
Second	262,681	130,972	83,245	(1,326)	2.72	2.66
Third	213,767	98,879	62,271	(348)	2.02	1.98
Fourth	145,407	(721,451)	(452,481)	(212)	(14.66)	(14.66)
Total	$ 820,815	$ (412,758)	$ (257,130)	$ (3,360)	$ (8.39)	$ (8 39)
2007:						
First	$ 130,079	$ 41,917	$ 26,445	$ 1,143	$ 0.89	$ 0.87
Second	156,410	48,557	30,523	987	1.02	1.00
Third	171,272	71,079	42,915	(633)	1.43	1.40
Fourth	196,360	83,003	52,705	(132,798)	1.75	1.71
Total	$ 654,121	$ 244,556	$ 152,588	$ (131,301)	$ 5.09	$ 4.98

There were no extraordinary items in 2008 or 2007. Our New Zealand operations are accounted for as discontinued operations. In the fourth quarter of 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and natural gas properties.

The sum of the individual quarterly net income (loss) per common share amounts may not agree with year-to-date net income (loss) 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 (loss) per common share because to do so would have been antidilutive.

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

None.

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 this report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required under the Exchange Act to be disclosed in this report. There were no significant changes in the Company’s internal controls that could significantly affect such controls subsequent to the date of their evaluation.

There was no change in our internal control over financial reporting during the quarter ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report On Internal Control Over Financial Reporting as of December 31, 2008 is included in Item 8. Financial Statements and Supplementary Data. The Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting is also included in Item 8.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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 12, 2009, 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 12, 2009, annual shareholders' meeting is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

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 12, 2009, annual shareholders' meeting is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

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 12, 2009, 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 12, 2009, annual shareholders' meeting is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 25, 2009, and the data contained therein are included in Item 8 hereof:

Management's Report on Internal Control Over Financial Reporting	45
Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting	46
Report of Independent Registered Public Accounting Firm	47
Consolidated Balance Sheets	48
Consolidated Statements of Income	49
Consolidated Statements of Stockholders' Equity	50
Consolidated Statements of Cash Flows	51
Notes to Consolidated Financial Statements	52

2. Financial Statement Schedules

[None]

3. Exhibits

3.1	Restated Articles of Incorporation of Swift Energy Company (incorporated by reference as Exhibit 3.3 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
3.2	Amended and Restated Bylaws of Swift Energy Company, as amended through December 28, 2005 (incorporated by reference as Exhibit 3.5 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
3.3	Certificate of Designation of Series A Junior Participating Preferred Stock of Swift Energy Company (incorporated by reference as Exhibit 3.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.1	Indenture dated as of June 23, 2004, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed June 25, 2004, File No. 1-08754).
4.2	First Supplemental Indenture dated as of June 23, 2004, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee, including the form of 7 5/8% Senior Notes (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form 8-K filed June 25, 2004, File No. 1-08754).

4.3	Second Supplemental Indenture dated as of December 28, 2005, between Swift Energy Company and Wells Fargo Bank. National Association, as Trustee (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.4	Amended and Restated Rights Agreement between Swift Energy Company and American Stock Transfer & Trust Company, dated March 31, 1999 (incorporated by reference to Swift Energy Company's Amendment No. 1 to Form 8-A filed April 7, 1999, File No. 1-08754).
4.5	Amendment No. 1 to the Rights Agreement dated December 12, 2005 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.3 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).

4.6	Assignment, Assumption, Amendment and Novation Agreement between Swift Energy Company, New Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent effective at 9:00 a.m. local time in Austin, Texas on December 28, 2005 (incorporated by reference as Exhibit 4.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.7	Amendment No. 2 to the Rights Agreement dated December 21, 2006 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 22, 2006, File No. 1-08754).
4.8	Form of indenture dated as of May 16, 2007 between Swift Energy Company and Wells Fargo Bank, National Association (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Registration Statement on Form S-3 filed May 17, 2007, File No. 333-143034).
4.9	First Supplemental Indenture dated as of June 1, 2007, between Swift Energy Company, Swift Energy Operating, LLC and Wells Fargo Bank, National Association relating to the 7-1/8% Senior Notes due 2017 (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed June 7, 2007, File No. 1-08754).
10.1 +	Amended and Restated Swift Energy Company 1990 Nonqualified Stock Option Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company's definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.2 +	Amendment to the Swift Energy Company 1990 Stock Compensation Plan, as of May 9, 2000 (incorporated by reference as Exhibit 4.2 to the Swift Energy Company registration statement No. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.3 +	Swift Energy Company 2001 Omnibus Stock Compensation Plan, as of January 1, 2001 (incorporated by reference as Exhibit 4.3 to the Swift Energy Company registration statement no. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.4 +	Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 12, 2005, File No. 1-08754).
10.5 +	Amendment No. 1 to the Swift Energy Company 2005 Stock Compensation Plan, as of May 9, 2006 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 12, 2006).

10.6 +	Employee Stock Purchase Plan (incorporated by reference as Exhibit 4(a) to Swift Energy Company's Registration Statement No. 33-80228 on Form S-8 filed June 15, 1994, File No. 1-08754).
10.7 +	Amended and Restated Employee Stock Purchase Plan dated June 1, 2006 (incorporated by reference to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, File No. 1-08754).
10.8	Form of Indemnity Agreement for Swift Energy Company officers (incorporated by reference as Exhibit 10.12 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).
10.9	Form of Indemnity Agreement for Swift Energy Company directors (incorporated by reference as Exhibit 10.12 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).

10.10 +	Consulting Agreement between Swift Energy Company and Virgil N. Swift effective as of July 1, 2006 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-08754).
10.11 +	Fourth Amended and Restated Agreement and Release by and between Swift Energy Company and Virgil Neil Swift, dated November 20, 2000 (incorporated by reference as Exhibit 10.13 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).
10.12 +	Forms of agreements for grant of incentive stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.19 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005, File No. 1-08754).
10.13	First Amended and Restated Credit Agreement effective as of June 29, 2004, among Swift Energy Company and Bank One, NA as Administrative Agent, Wells Fargo Bank, National Association as Syndication Agent, BNP Paribas, as Syndication Agent, Caylon, 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 (incorporated by reference as Exhibit 10.2 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
10.14	First Amendment to First Amended and Restated Credit Agreement effective as of November 1, 2005 by and among Swift Energy Company, JP Morgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Sydication Agent, BNP Paribas, as Syndication Agent, Caylon, as Documentation Agent, and Societe Generale, as Documentation Agent. (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005, File No. 1-08754).
10.15	Second Amendment to First Amended and Restated Credit Agreement effective as of December 28, 2005, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent (incorporated by reference as Exhibit 10.23 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005, File No. 1-08754).

10.16	Third Amendment to First Amended and Restated Credit Agreement effective as of October 2, 2006, by and among Swift Energy Company and Swift Energy Operating, LLC, and, J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent (incorporated by reference to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006, File No. 1-08754).
10.17	Eighth Amendment to Lease Agreement between Swift Energy Company and Greenspoint Plaza Limited Partnership dated as of June 30, 2004 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
10.18	Purchase and Sale Agreement dated as of August 24, 2006 but effective as of April 1, 2006, between Swift Energy Operating, LLC and BP America Production Company.

10.19+ Amendment No. 2 to the Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 99.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007 filed May 4, 2007).

10.20+ Amendment No. 3 to the Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10 to Swift Energy Company's Form 8-K filed May 11, 2007, File No. 1-08754).

10.21 Asset Purchase and Sale Agreement between Escondido Resources LP and Swift Energy Operating, LLC dated as of September 4, 2007 but effective as of July 1, 2007 (incorporated by reference as Exhibit 99.1 to the Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 filed May 4, 2007).

10.22 Agreement for Sale and Purchase of Assets between Swift Energy New Zealand Limited, Swift Energy New Zealand Holdings Limited, Southern Petroleum (New Zealand) Exploration Limited, Origin Energy Recourses NZ (SPV1) Limited, Origin Energy Resources NZ (SPV2) Limited and Origin Energy Limited effective December 1, 2007.

10.23 Fourth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2008, by and among Swift Energy Company and Swift Energy Operating, LLC, and J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, N.A., as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Document Agent (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008 filed August 8, 2008).

10.24+ First Amended and Restated 2005 Stock Compensation Plan dated November 4, 2008 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.25+ Swift Energy Company Change of Control Severance Plan dated November 4, 2008 (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.26+ Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift dated November 4, 2008 (incorporated by reference as Exhibit 10.3 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.27+

	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Bruce H. Vincent dated November 4, 2008 (incorporated by reference as Exhibit 10.4 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.28+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Alton D. Heckaman dated November 4, 2008 (incorporated by reference as Exhibit 10.5 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.29+	Executive Employment Agreement between Swift Energy Company and Robert J. Banks dated November 4, 2008 (incorporated by reference as Exhibit 10.6 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.30+	Amended and Restated Executive Employment Agreement between Swift Energy Company and James P. Mitchell dated November 4, 2008 (incorporated by reference as Exhibit 10.7 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.31+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and James M. Kitterman dated November 4, 2008 (incorporated by reference as Exhibit 10.8 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.32+*	Employee Stock Purchase Plan, Generally Amended and Restated as of January 1, 2009.
12 *	Swift Energy Company Ratio of Earnings to Fixed Charges.
21 *	List of Subsidiaries of Swift Energy Company.
23.1 *	Consent of H.J. Gruy and Associates, Inc.
23.2 *	Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31.1 *	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32 *	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	The summary of H.J. Gruy and Associates, Inc. reported February 3, 2009.

* 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:
/s/ Terry E. Swift
Terry E. 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:

Signatures	Title	Date
/s/ Terry E. Swift Terry E. Swift	Director Chief Executive Officer	February 26, 2009
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 26, 2009
/s/ David W. Wesson David W. Wesson	Controller Principal Accounting Officer	February 26, 2009
/s/ Deanna L. Cannon Deanna L. Cannon	Director	February 26, 2009
/s/ Raymond E. Galvin Raymond E. Galvin	Director	February 26, 2009

85

/s/ Douglas J. Lanier Douglas J. Lanier	Director	February 26, 2009
/s/Greg Matiuk Greg Matiuk	Director	February 26, 2009
/s/ Henry C. Montgomery Henry C. Montgomery	Director	February 26, 2009
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	February 26, 2009
/s/ Charles J. Swindells Charles J. Swindells	Director	February 26, 2009
/s/ Bruce H. Vincent Bruce H. Vincent	Director	February 26, 2009