SWIFT ENERGY CO
Form 10-K
February 26, 2010

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, 2009

Commission File Number 1-8754

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

TEXAS (State of Incorporation)	20-3940661 (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 þNo

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 No þ

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 þ	Accelerated filer	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

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, 2009, the last business day of June 2009, was approximately $503,004,459.

The number of shares of common stock outstanding as of January 31, 2010 was 37,524,307.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 2010	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 2010

PART I

Item 1. Business

See pages 25 and 26 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 2009, we had estimated proved reserves from our continuing operations of 112.9 MMBoe with a PV-10 of $1.3 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 2009 were comprised of approximately 39% crude oil, 43% natural gas, and 18% NGLs; and 50% of our total proved reserves were proved developed. Our proved reserves are concentrated with 56% of the total in Louisiana, 43% 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
Other South Texas 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
High Island field

- Other

Non-Core 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 108.8 MMBoe to 112.9 MMBoe over the five-year period ended December 31, 2009. Over the same period, our annual production has grown from 7.0 MMBoe to 9.1 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 2009, our proved reserves decreased by 3%, due mainly to lower prices used in the 2009 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. We have replaced 109% of our production on average over the last five years.

We currently plan to balance our 2010 capital expenditures with our 2010 cash flow and cash on hand. Our 2010 capital expenditures are currently budgeted at $300 million to $375 million, net of minor non-core dispositions and excluding any property acquisitions. Approximately two-thirds of our capital budget is targeted for our South Texas core area, while one-quarter is planned for our Southeast Louisiana core area. For 2010, we anticipate an increase in production volumes of 3% to 7% over 2009 levels and expect reserves to grow 5% to 10% over 2009 levels.

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, competition within our industry, adverse weather conditions, commodity market factors, the requirement of new or upgraded infrastructure at the production site, technological advances, and governmental regulations, could limit our ability to drill wells, access reserves, 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.

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 $8.47, $10.44 and $6.68 per Boe in 2009, 2008, and 2007, 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, 2009. 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 9,600 Boe for the quarter ended December 31, 2009. We have also increased our proved reserves in the area from 7.7 million Boe to approximately 27.2 million Boe as of December 31, 2009. 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, 2009, our debt to capitalization was approximately 41%, while our debt to proved reserves ratio was $4.17 per Boe, and our debt to PV-10 ratio was 36%. 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 64 oil and gas technical 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 an average of 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 acquisition, licensing and pre-stack time and depth imaging, advanced attributes, pore-pressure analysis, inversion and detailed field reservoir depletion planning. In 2004, we recorded a 3-D seismic survey covering our Lake Washington field, and in 2006 we recorded a second 3-D survey in and around our Cote Blanche Island field. We now have proprietary pre-stack time and depth migrated seismic data covering over 4,000 square miles in South Louisiana. These data have been merged into two large data volumes, 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 200 square miles of 3-D seismic data. In 2008, we licensed an additional 350 square miles of 3-D seismic data over and near our AWP field. As these data are processed and 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. By December 31, 2009, we have successfully drilled and completed five horizontal multistage fracture completions 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.

Swift Energy's success at drilling both in South Texas and in Louisiana can be marked by requiring excellence in engineering. This was accomplished by elevating the quality of engineering first and operations second. A premium was placed on well planning. Drilling guidelines and design specifications were developed and implemented as best practices and standards, respectively, from which all planning and execution was derived. The emphasis on well planning permeated throughout the organization and the results of that planning has shown up in performance across all drilling operations. Lastly, the quality of the equipment and field personnel, together with a complete drilling process has been enforced. This has been the final mixture of resources that have aided Swift Energy to move toward becoming a top tier Company.

Item 2. Properties

Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2009 year-end proved reserves from continuing operations of 112.9 MMBoe and production of 9.1 MMBoe by area:

Field/Area	Developed (MMBoe)	Undeveloped (MMBoe)	Total (MMBoe)	% of Reserves	% of Production	% Oil and NGLs
Lake Washington	12.3	14.9	27.2	24.1%	39.7%	92.7%
Bay de Chene	3.1	1.1	4.1	3.7%	13.1%	43.0%
Total Southeast Louisiana	15.4	16.0	31.3	27.7%	52.8%	86.1%
AWP	16.3	13.2	29.6	26.2%	18.4%	38.1%
Sun TSH	8.3	3.2	11.4	10.1%	8.0%	50.7%
Briscoe Ranch	1.2	0.8	2.0	1.7%	2.0%	53.8%
Las Tiendas	0.3	0.0	0.3	0.3%	0.5%	17.9%
Other South Texas	0.2	0.0	0.2	0.2%	1.2%	6.6%
Total South Texas	26.3	17.2	43.5	38.5%	30.1%	41.8%
Brookeland	1.9	2.6	4.5	4.0%	2.4%	58.2%
South Bearhead Creek	4.0	2.8	6.8	6.0%	5.3%	68.5%
Masters Creek	2.1	5.2	7.3	6.5%	1.4%	70.9%
Chunchula	1.2	0.2	1.4	1.2%	0.4%	27.0%
Total Central Louisiana / East Texas	9.1	10.8	20.0	17.7%	9.5%	64.2%
Horseshoe Bayou /Bayou Sale	2.8	3.3	6.1	5.4%	4.0%	25.9%
Jeanerette	1.0	4.1	5.2	4.6%	0.9%	7.8%
Cote Blanche Island	0.7	4.7	5.4	4.8%	0.6%	78.4%
Bayou Penchant	0.1	0.0	0.1	0.1%	0.7%	55.5%
High Island	1.2	0.0	1.2	1.1%	1.0%	100.0%
Total South Louisiana	5.8	12.1	18.0	15.9%	7.2%	41.6%
Other	0.2	0.0	0.2	0.2%	0.4%	4.3%
Total	56.8	56.1	112.9	100%	100%	58.0%

Focus Areas

Our operations are primarily focused in four core areas identified as Southeast Louisiana, South Texas, Central Louisiana/East Texas, and South Louisiana. In addition, we have a strategic growth area with 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, 2009, we owned drilling and production rights in 24,624 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 93% of our proved reserves of 27.2 MMBoe in this field at December 31, 2009, consisted of oil and NGLs. Oil and natural gas from approximately 107 currently 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 2009, we drilled and completed 4 out of 5 development wells in Lake Washington. We also drilled 2 exploratory wells and successfully completed one of them in Lake Washington. At year-end 2009, we had 96 proved undeveloped locations in this field. Our planned 2010 capital expenditures in the field will include drilling 10 to 15 wells and performing recompletions on up to 10 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, 2009, we owned drilling and production rights in approximately 16,035 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 was shut in from September 2008 through August 2009 due to damages that occurred from Hurricane Gustav in 2008. The Bay De Chene facility was rebuilt and commissioned in August 2009. During 2009 we did not drill any wells in the Bay De Chene field. At year-end 2009, we had three proved undeveloped locations in the Bay de Chene field. During 2010, we plan to drill from 2 to 5 wells in Bay de Chene.

South Texas

AWP. The AWP field is located in McMullen County, Texas. As of December 31, 2009 we owned drilling and production rights in 71,997 net acres in the field and were operating 569 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 2009, we completed 11 out of 11 development wells drilled in the AWP field in South Texas and performed 29 fracture enhancements. At year-end 2009, we had 83 proved undeveloped locations in the field. Our planned 2010 capital expenditures will include drilling up to 4 horizontal wells in the Olmos formation, and performing approximately 30 fracture enhancements for wells in this field.

Eagle Ford Joint Venture. In November 2009, we entered into a joint venture agreement with an independent oil and gas producer to jointly develop and operate an approximate 26,000 acre portion of our Eagle Ford Shale acreage in McMullen County, Texas. Swift Energy retains a 50% interest in the joint venture that calls for joint development of this area located in our AWP field and covers leasehold interests beneath the Olmos formation (including the Eagle Ford Shale formation) extending to the base of the Pearsall formation. We received approximately $26 million in cash related to this transaction and approximately $13 million of carried interests which would be credited against future drilling costs.

We plan to drill up to 9 wells in 2010 through our joint venture and up to 6 wells on our own in 2010 targeting our Eagle Ford shale acreage in the AWP area.

Sun TSH, Briscoe Ranch, and Las Tiendas. In October 2007, Swift Energy 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, 2009, we owned drilling and production rights in 97,502 net acres in these fields (21,882 in Sun TSH, 66,998 in Briscoe Ranch, 8,622 in Las Tiendas). In 2009, we drilled and completed 2 development wells drilled in these fields. At year-end 2009, we were operating 243 wells in these fields and had 118 proved undeveloped locations. Our planned 2010 capital expenditures include drilling from 6 to 10 wells in these fields all targeting the Eagle Ford shale acreage in these areas.

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, 2009, we owned drilling and production rights in 56,355 net acres and 3,500 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 58% oil and natural gas liquids. During 2009 we did not drill any wells in the Brookland field and at year-end 2009, we had 10 proved undeveloped locations in the field.

In August 2009 we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. Swift Energy, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $4.2 million related to this transaction. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

Masters Creek. As of December 31, 2009, we owned drilling and production rights in 52,964 net acres and 91,594 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 71% oil and NGLs. We did not drill any wells in this field during 2009 and at year-end 2009, we had nine proved undeveloped locations. During 2010, we plan to drill 1 well in Masters Creek.

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, 2009, we owned drilling and production rights in 8,074 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 feet; Middle and Upper Wilcox – 9,000 to 12,000 feet; and Cockfield – 8,000 to 9,000 feet. In 2009, we did not drill any wells in this field and at year-end 2009, we had 18 proved undeveloped locations in this 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, 2009, we owned drilling and production rights in 6,556 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 2009 we did not drill any wells in the Cote Blanche Island field, and at year-end 2009, we had 18 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, 2009, we owned drilling and production rights in a total of 23,309 net acres in these fields (5,700 in Bayou Sale, 9,524 in Horseshoe Bayou, 5,088 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. Swift Energy holds an average 43% working interest in the wells in this non-operated field, which produces from a number of Middle Miocene sands.

In 2009, we did not drill any wells in our Bayou Sale, Horseshoe Bayou and Jeanerette fields. At year-end 2009, we had 47 proved undeveloped locations in the Bayou Sale, Horseshoe Bayou and Jeanerette fields.

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, 2009, we owned drilling and production rights in 2,041 net acres in this field. During 2009 we did not drill any wells in the High Island field.

Other

Four Corners. At the end of 2009, we had approximately 21,507 net acres leased in the Four Corners area of southwest Colorado.

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New Zealand Areas (Discontinued Operations)

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of operations 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 nine 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. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending final resolution of this litigation.

In February 2009, the first $5.0 million payment from the sale of our last permit was released to our attorneys who were holding these proceeds in trust for Swift Energy. In April 2009, after an injunction limiting our ability to use such funds was dismissed in favor of Swift Energy, the proceeds were transferred to our bank account in the United States.

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, 2009, 2008, and 2007, and in New Zealand as of December 31, 2007. As of December 31, 2009 and 2008, our domestic proved reserves comprise all of the company’s proved reserves. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us. Our Director of Reserves & Evaluations, the primary technical person responsible for overseeing the preparation of our reserves estimates, is a Licensed Professional Engineer, holds a bachelor’s and a master’s degree in chemical engineering, is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and has over 20 years of experience supervising or preparing reserves estimates. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, has audited 96% of our 2009 domestic proved reserves, 97% of our domestic proved reserves for 2008 and 100% of our domestic proved reserves for 2007. The audit by H.J. Gruy and Associates, Inc. conformed to the meaning of the term “reserves audit” as presented in Regulation S-K, Item 1202. The technical person at H.J. Gruy and Associates, Inc. primarily responsible for overseeing the audit, is a Licensed Professional Engineer, holds a degree in petroleum engineering, is past Chairman of the Gulf Coast Section of the Society of Petroleum Engineers, is past President of the Society of Petroleum Evaluation Engineers and has over 20 years experience overseeing reserves audits. Based on its audits, 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 was conducted in accordance with Regulation S-K, Item 1202. The reserves audit performed by H.J. Gruy and Associates, Inc. is one control procedure used during the reserves estimation process to ensure the integrity of our reserves estimates. In addition to the reserves audit, the reserves estimation process is conducted by senior engineers with a minimum of 10 years of reservoir engineering experience, and multiple levels of review and reconciliation are applied to their estimates before the estimates are finalized.

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 U.S. Securities and Exchange Commission within Regulation S-K, Item 1202, a reserves audit is the process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities. 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, for the year ended December 31, 2009, are made based on either the preceding 12-months' average price based on closing prices on the first business day of each month, or prices defined by existing contractual arrangements 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. For the years ended December 31, 2008 and 2007, these same amounts are based on the same methodology except for the use of period-end oil and natural gas sales prices. 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.

Our hedges at year-end 2009 consisted of natural gas collars and price floors with strike price ranges outside the current period-end price and did not affect prices used in these calculations. The 12-month average 2009 prices for domestic operations were $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL compared to $4.96 per Mcf of natural gas, $44.09 per barrel of oil, and $25.39 per barrel of NGL at year end 2008 and $6.65 per Mcf of natural gas, $93.24 per barrel of oil, and $56.28 per barrel of NGL at year-end 2007. At December 31, 2009 and 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. 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.

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, 2009, 2008, and 2007. 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 (MBoe amounts shown below are based on a natural gas conversion factor of 6 Mcf to 1 Boe):

	As of December 31, 2009		
	Total	Domestic	Discontinued Operations
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	155,405	155,405	---
Proved undeveloped	135,148	135,148	---
Total	290,553	290,553	---
Oil, NGL, and Condensate reserves (MBbl):			
Proved developed	30,897	30,897	---
Proved undeveloped	33,606	33,606	---
Total	64,503	64,503	---
Total Estimated Reserves (MBoe)	112,928	112,928	---
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$766	$766	$---
Proved undeveloped	557	557	---
PV-10 Value	$1,323	$1,323	$---

	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, NGL, and Condensate 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	$832	$832	$---
Proved undeveloped	481	481	---
PV-10 Value	$1,313	$1,313	$---

	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, NGL, and Condensate 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	$2,025	$1,961	$65
Proved undeveloped	1,823	1,790	32
PV-10 Value	$3,848	$3,751	$97

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 provides a reconciliation between PV-10 and the standardized measure of discounted future net cash flows:

	As of December 31, 2009		
	Total	Domestic	Discontinued Operations
(in millions)			
PV-10 Value	$1,323	$1,323	$ ---
Future income taxes (discounted at 10%)	(302)	(302)	---
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$1,021	$1,021	$ ---

	As of December 31, 2008		
	Total	Domestic	Discontinued Operations
(in millions)			
PV-10 Value	$1,313	$1,313	$ ---
Future income taxes (discounted at 10%)	(280)	(280)	---
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	$3,848	$3,751	$ 97
Future income taxes (discounted at 10%)	(1,212)	(1,211)	(1)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$2,636	$2,540	$ 96

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, 2009:

Year Added	Volume (MMBoe)	% of PUD Volumes	PV-10 Value (in millions)	% of PUD PV-10 Value
2009	8.5	15%	$36.1	7%
2008	6.3	11%	61.8	11%
2007	10.3	18%	79.1	14%
2006	5.5	10%	76.5	14%
2005	8.2	15%	99.4	18%
2004	5.4	10%	111.4	20%
Prior to 2004	11.9	21%	93.5	16%
Total	56.1	100%	$557.8	100%

In our AWP field, we recorded 8.3 MMBoe of additional proved undeveloped reserves during 2009 based on the results of the horizontal drilling program conducted in the area during the year. We also spent approximately $17.7 million in capital expenditures during the year to convert proved undeveloped reserves to proved developed reserves in the AWP and Lake Washington fields. As of December 31, 2009, approximately 15% of our total proved reserves consisted of undeveloped reserves added prior to 2005, primarily in the Lake Washington, AWP, Masters Creek and Brookeland fields. Our efforts to convert unproved locations during 2009 were significantly impacted by operating decisions made at that time in relation to the global financial crisis and depressed oil and natural gas prices, which significantly lowered capital expenditures.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2009, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 112.9 MMBoe by approximately 0.5 MMBoe, and increase the domestic PV-10 Value of $1.3 billion by approximately $89 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.5 MMBoe and decrease the domestic PV-10 Value by approximately $88 million.

As of December 31, 2009 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.5 MMBoe and increase the domestic PV-10 Value by approximately $26 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.2 MMBoe and decrease the domestic PV-10 Value by approximately $26 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, 2009:			
Gross	469	825	1,294
Net	406.6	758.9	1,165.5
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

(1) Excludes 59 service wells in 2009 and 65 service wells in both 2008 and 2007.
(2) Includes 49 wells in New Zealand in 2007.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2009:

	Developed(1)(2)		Undeveloped(3)(4)	
	Gross	Net	Gross	Net
Alabama	8,120	1,580	176	1
Colorado	---	---	31,888	21,507
Louisiana	120,537	102,046	32,193	26,587
Texas	154,786	112,990	131,959	125,717
Wyoming	640	151	6,651	4,664
Offshore Louisiana	4,609	277	---	---
All other states	---	---	721	257
Total	288,692	217,044	203,588	178,733

(1)

Fee Mineral acres 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) In total, our Eagle Ford shale position encompassed approximately 89,000 gross and 76,000 net acres in our South Texas region. A portion of this Eagle Ford acreage is below developed Olmos acreage.

(3) Subsequent to 12/31/2009 leases covering 60,316 gross and 60,158 net undeveloped have expired in our Briscoe Ranch field in the South Texas region.

(4) We also own overriding royalty interest ranging between 1% and 7.5% in 31,325 undeveloped acres in Texas and Wyoming.

Drilling and Other Exploratory and Development Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2009:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2009	Exploratory — Domestic	2	1	1	2	1	1
	Development — Domestic	18	17	1	18	17	1
	Exploratory — New Zealand	—	—	—	—	—	—
	Development — New Zealand	—	—	—	—	—	—
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	—	—	—	—	—	—

Additional development activities during 2008 included the commissioning of our fourth production platform, the Westside facility, in the Lake Washington field.

Present Activities

As of December 31, 2009, we were in the process of drilling four wells in South Texas (3.5 net wells) and one well in Southeast Louisiana in which we have a 100% working interest. We have also continued the production optimization program in the Lake Washington field, involving gas lift enhancements and sliding sleeve shifts to change productive zones, to assist in mitigating natural field declines.

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 2009 totaled $11.4 million and ranged from $374 to $2,888 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. Shell Oil Company and its affiliates accounted for approximately 48% and 28% of our gross oil and gas sales in 2009 and 2008, respectively. In 2008, Chevron and its domestic affiliates accounted for 25% of our gross oil and gas sales. No other purchasers accounted for more than 10% of our total oil and gas sales for the past two years. 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 natural 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. Processing revenues are received from Enterprise. The residue gas is sold at downstream connections with the Enterprise pipeline at prevailing market prices. Oil production is transported to market by truck or pipeline and sold at prevailing market prices.

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 Energy 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 sell the oil production to various purchasers at prevailing market prices. The oil 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, 2009:

	Year Ended December 31,		
	2009	2008	2007
Net Sales Volume:			
Oil (MBbls)	4,346	5,420	7,045
Natural Gas Liquids (MBbls)	1,183	1,211	774
Natural gas (MMcf) 1	19,211	18,872	15,288
Total (MBoe)	8,731	9,777	10,368
Average Sales Price:			
Oil (Per Bbl)	$60.07	$101.38	$71.92
Natural Gas Liquids (Per Bbl)	$31.36	$57.15	$49.72
Natural gas (Per Mcf)	$3.83	$9.28	$7.04

Average Production Cost (Per Boe sold) 2	$8.79	$10.73	$6.84

1 Excludes gas consumed in operations that is included in reported production volumes
2 Excludes severance and ad valorem taxes

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.

xThe following table provides a summary of our production, average sales prices, and average production costs for fields containing 15% or more of our total proved reserves as of December 31, 2009:

	Year Ended December 31,		
	2009	2008	2007
Lake Washington			
Net Production:			
Oil (MBbls)	3,199	3,999	5,719
Natural Gas Liquids (MBbls)	75	178	202
Natural gas (MMcf) 1	931	2,309	3,145
Total (MBoe)	3,430	4,562	6,446
Average Sales Price:			
Oil (Per Bbl)	$59.62	$100.21	$71.71
Natural Gas Liquids (Per Bbl)	$43.55	$78.02	$51.12
Natural gas (Per Mcf)	$4.37	$9.68	$6.93
Average Production Cost (Per Boe sold) 2	$9.13	$8.59	$4.10
AWP			
Net Production:			
Oil (MBbls)	197	197	139
Natural Gas Liquids (MBbls)	496	344	225
Natural gas (MMcf) 1	5,623	5,125	4,436
Total (MBoe)	1,630	1,395	1,103
Average Sales Price:			
Oil (Per Bbl)	$58.52	$95.81	$71.80
Natural Gas Liquids (Per Bbl)	$29.68	$50.94	$47.69
Natural gas (Per Mcf)	$3.63	$9.15	$7.27
Average Production Cost (Per Boe sold) 2	$6.51	$9.35	$9.80

Excludes gas consumed in operations that is included in reported production volumes
2 Excludes severance and ad valorem taxes

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, 2009, we had natural gas price collars in effect for the contract months of January through March 2010 that covered a portion of our natural gas production for January to March 2010. The natural gas price collars contain a floor that covers notional volumes of 200,000 MMBtu per month and a call that covers 100,000 MMBtu per month, for the same period. The weighted average floor price is $4.50 and the weighted average call price is $6.80 per MMBtu. At December 31, 2009, we had natural gas price floors in effect for the contract months of January through June 2010 that covered a portion of our natural gas production for January to June 2010. These floors cover additional natural gas production of 2,400,000 MMBtu from January through March 2010 and 2,640,000 MMBtu from April through June 2010 with strike prices ranging between $4.55 and $4.96.

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, 2009, we employed 295 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2009, we occupied approximately 202,355 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 $440,000 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 all the material risks relating to our business activities.

Enactment of Congressional and regulatory proposals under consideration could
negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been proposed or are under consideration by the Obama administration, Congress and various federal agencies. Among these proposals are: (1) climate change legislation introduced in Congress, Environmental Protection Agency regulations, carbon emission "cap-and-trade" regimens, and related proposals, none of which have been have been adopted in final form; (2) proposals contained in the President's budget, along with legislation introduced in Congress, none of which have been enacted by both houses of Congress, to repeal various tax deductions or exemptions available to oil and gas producers, such as the tax deduction for intangible drilling and development costs, which if eliminated could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; and (3)legislation being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, which could affect Company operations, their effectiveness, and the costs thereof. Any such future laws and regulations could result in increased costs or additional operating restrictions, and could have an effect on demand for oil and gas or prices at which it can be sold. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

The continuing pressure on the global credit and financial markets could materially and
adversely impact our financial results.

As widely reported, global credit and financial markets have been experiencing extreme disruptions since the second half of 2008, including, severely diminished liquidity and credit availability, volatility in consumer confidence, declines in economic growth, increases in unemployment rates, and uncertainty about economic stability. We cannot assure you that there will not be further deterioration in credit, financial, or commodities markets. These economic conditions have 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.

Our operating results may be adversely affected if economic conditions impact the financial viability of our insurers, oil and gas purchasers, suppliers and commodity derivatives counterparties.

Global economic conditions may adversely affect the financial viability of and increase the credit risk associated with our 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.

Negative credit market conditions may adversely 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 that could affect our ability to fund our future capital projects. Negative credit market conditions could materially affect our liquidity and 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 future redeterminations or the effect of then current oil and gas prices on that process. Additionally, our line of credit matures in October 2011, and although it has a zero balance as of December 31, 2009, long-term restriction or freezing of the capital markets may affect the availability or pricing of our renewal of the line of credit.

Approximately 44% of our 2009 reserves and 60% of our 2009 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.

Hurricane activity in 2007 and 2008 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 for periods ending before December 31, 2009. Starting with our financial statements ending December 31, 2009 the unescalated prices are now calculated using a twelve month rolling average price from the first business day of each month. Capital costs in excess of the ceiling must be permanently written down. Low oil and gas prices at December 31, 2008 and March 31, 2009 led to $473.1 and $50.0 million non-cash after-tax write-downs of our oil and gas properties, respectfully. If oil and gas prices decline, 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 in subsequent 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 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, 2009, our total debt comprised approximately 41% 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, 2009, approximately 50% 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 contaminate
- 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. Our hedges at year-end 2009 consisted of natural gas collars and price floors with strike price ranges outside the current period-end price. 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.

Developed Oil and Gas Reserves — Oil and natural gas reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods. 1

Development Well — A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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 Energy 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 Energy.

Exploratory Well — A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another 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 Oil and Gas Reserves — Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. For reserves calculations on or after December 31, 2009, economic conditions include prices 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. 3
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 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, 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.
Undeveloped Oil and Gas Reserves — Oil and natural gas reserves of any category 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. 4

Notes to Abbreviations and Terms Above

The Regulation S-X definitions below refer to the revised definitions effective January 1, 2010.

1. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(6) 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)(13) 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)(22) 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)(31) 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 2009 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, 2008 and 2009

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 2008 and 2009 were as follows:

	2008				2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$39.64	$44.80	$36.83	$15.30	$4.95	$7.46	$13.09	$20.88
High	$49.98	$66.06	$67.03	$37.83	$21.23	$19.38	$25.61	$25.43

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 193 stockholders of record as of December 31, 2009.

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.

Item 6. Selected Financial Data

(in thousands except per share and well amounts)	2009	2008	2007	2006	2005
Total Revenues from Continuing Operations (1)	$370,445	$820,815	$654,121	$550,836	$354,365
Income (Loss) from Continuing Operations, Before Income Taxes and Change in Accounting Principle (1)	$(64,617)	$(412,758)	$244,556	$248,308	$156,129
Income (Loss) from Continuing Operations (1)	$(39,076)	$(257,130)	$152,588	$151,074	$97,880
Net Cash Provided by Operating Activities - Continuing Operations	$226,176	$582,027	$442,282	$383,241	$236,791
Per Share and Share Data					
Weighted Average Shares Outstanding(1)	33,594	30,661	29,984	29,265	28,496
Earnings per Share--Basic(1)	$(1.16)	$(8.39)	$5.09	$5.16	$3.43
Earnings per Share--Diluted(1)	$(1.16)	$(8.39)	$4.98	$5.03	$3.34
Shares Outstanding at Year-End	37,457	30,869	30,179	29,743	29,010
Book Value per Share at Year-End	$18.12	$19.47	$27.70	$26.83	$20.94
Market Price					
High	$25.61	$67.03	$47.72	$51.84	$50.01
Low	$4.95	$15.30	$35.98	$35.48	$24.77
Year-End Close	$23.96	$16.81	$44.03	$44.81	$45.07
Assets					
Current Assets	$108,600	$78,086	$199,950	$83,783	$110,199
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,315,964	$1,431,447	$1,760,195	$1,239,722	$862,717
Total Assets	$1,434,765	$1,517,288	$1,969,051	$1,585,682	$1,204,413
Liabilities					
Current Liabilities	$103,604	$153,499	$210,161	$145,471	$98,421
Long-Term Debt	$471,397	$580,700	$587,000	$381,400	$350,000
Total Liabilities	$755,866	$916,411	$1,132,997	$787,765	$597,094
Stockholders’ Equity	$678,899	$600,877	$836,054	$797,917	$607,318
Number of Domestic Employees	295	334	298	272	236
Domestic Producing Wells					
Swift Operated	1,146	1,168	1,091	926	854
Outside Operated	148	159	127	112	69
Total Domestic Producing Wells	1,294	1,327	1,218	1,038	923

Domestic Wells Drilled (Gross)	20	126	69	55	54
Domestic Proved Reserves					
Natural Gas (Bcf)	290.6	292.4	343.8	269.7	225.3
Oil, NGL, & Condensate (MMBbls)	64.5	67.7	76.5	73.5	69.8
Total Domestic Proved Reserves (MMBoe equivalent)	112.9	116.4	133.8	118.4	107.3
Domestic Production (MMBoe equivalent)	9.1	10.0	10.6	9.4	7.2
Domestic Average Sales Price (2)					
Natural Gas (per Mcf produced)	$3.48	$8.54	$6.42	$6.44	$7.40
Natural Gas Liquids (per barrel)	$31.36	$57.15	$49.72	$38.70	$34.00
Oil (per barrel)	$60.07	$101.38	$71.92	$64.28	$53.45
Boe Equivalent	$41.05	$79.00	$61.49	$56.89	$49.61

(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 operations. 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. Natural gas sales prices represents the amount realized per MCF of production.

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, 2009, 2008, and 2007 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 one of the largest producers of crude oil in the state of Louisiana, due to our South Louisiana operations, with oil constituting 48% of our 2009 production, and together with oil and natural gas liquids ("NGLs") making up 61% of our 2009 production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in 2009.

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 New Zealand operations discontinued in 2007.

2009 Oil and Natural Gas Pricing

Significantly reduced prices for oil and natural gas have had a significant impact on our cash flow, capital expenditures, and liquidity over the past year. Both oil and natural gas prices we received in 2009 were lower than the average prices we received in 2008, with a 48% decline in average prices per BOE received. These declines reduced our cash flow from operations in 2009 and will continue to reduce our cash flow from operations in future periods if prices remain at these lower levels. Although prices at the end of 2009 were higher than the average prices we received during 2009, these prices were still significantly lower than the prices we received during 2008.

Financial Condition

We raised $108.8 million through an underwritten public stock offering in August 2009. We issued 6.21 million shares of our common stock at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million.

In November 2009, we issued $225.0 million of 8-7/8% senior notes due 2020 at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%.

In December 2009, we redeemed all $150.0 million of our 7-5/8% senior notes due 2011 and recorded a charge of $4.0 million related to the redemption of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statement of operations. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

We used the proceeds from this stock sale and note offering, less costs to redeem our senior notes due 2011, to pay down the outstanding balance on our credit facility.

Our debt to capitalization ratio decreased to 41% at December 31, 2009, as compared to 49% at year-end 2008, as paid in capital increased and our total debt balance decreased due to our stock offering, offset somewhat by a retained earnings decrease due to our net loss for 2009, which included a non-cash write-down of our oil and gas properties.

Operating Results- Prior Year Comparison

In 2009 we had revenues of $370.4 million, a decrease of 55% compared to 2008 levels. Our weighted average sales price received decreased 48% to $41.05 per Boe for 2009 from $79.00 per Boe in 2008. This $450.4 million decrease in revenues from 2008 levels resulted from lower oil, natural gas, and NGL prices during 2009, along with a 10% decrease in production mainly due to natural declines in our Lake Washington field.

Our overall costs and expenses decreased in 2009 by $798.5 million when compared to 2008 levels. The 2008 period included a non-cash write-down of our oil and gas properties of $754.3 million in the fourth quarter of 2008, while the 2009 period included a non-cash write-down of our oil and gas properties of $79.3 million in the first quarter of 2009. Depreciation, depletion and amortization expense also decreased 25%, mainly due to our lower depletable property base in the 2009 period due to the non-cash write-downs mentioned above, lower production in the 2009 period, partially offset by a reduction in reserves volumes when compared to the 2008 period. Severance and other taxes decreased 49% mainly due to decreased oil and gas revenues. Lease operating costs decreased by 27% due to less hurricane related costs, decreased workover costs, decreased natural gas processing costs, and a decrease in plant operating expense resulting from targeted cost reduction initiatives.

Our loss from continuing operations for 2009 was $39.1 million. If the $79.3 million ($50.0 million after tax) first quarter 2009 non-cash write-down of our oil and gas properties is excluded our income after tax would have been $11.0 million. This compares to a loss from continuing operations of $257.1 million. If the $754.3 million ($473.1 million after tax) fourth quarter 2008 non-cash write-down of our oil and gas properties is excluded our income after tax would have been $216.0 million for 2008.

Operating Activities

In our South Texas core area, the first three wells of our 2009 horizontal drilling and completion program targeting the Olmos formation at the AWP field finished drilling and were completed, while another horizontal well was completed in January 2010. We also drilled seven vertical wells in the AWP field.

In January 2010, we commenced drilling two wells targeting the Eagle Ford shale formation and expect them both to be completed during March 2010.

Additionally, in excess of 150 wells in the AWP field have been identified as candidates for additional fracture stimulation. In 2009, twenty nine of these wells have been re-fractured. We plan to perform thirty re-fracture operations in 2010.

In November 2009, we entered into a joint venture agreement with an independent oil and gas producer to jointly develop and operate an approximate 26,000 acre portion of our Eagle Ford Shale acreage in McMullen County, Texas. Swift Energy retains a 50% interest in the joint venture that calls for joint development of this area located in our AWP field and covers leasehold interests beneath the Olmos formation (including the Eagle Ford Shale formation) extending to the base of the Pearsall formation. We received approximately $26 million in cash related to this transaction and approximately $13 million of carried interests. The first well under the joint venture agreement, in which we own a 50% interest, commenced drilling in late December 2009 to test the Eagle Ford shale formation and is expected to be completed in the first quarter of 2010.

In the Central Louisiana/East Texas core area, we recently entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $4.2 million related to this transaction.

At Lake Washington during 2009, a production optimization program involving gas lift enhancements and sliding sleeve shifts to change productive zones was continued to assist in mitigation of natural field declines. In 2009 we completed 29 sliding sleeve changes, 9 gas lift modifications, and 3 acid jobs. We also drilled 5 shallow wells in the later part of 2009, completing four of them while one was unsuccessful.

In our Southeast Louisiana and South Louisiana core areas we have completed 4,000 square miles of 3D prestack seismic depth migration over our Lake Washington, Shasta, Bay de Chene, High Island, Cote Blanche Island, Horseshoe Bayou , Bayou Sale and Jeanerette fields. This depth migration and updated “salt model” has significantly improved and refined our understanding of the complex traps associated with salt bodies and will enable us to more accurately plan and position our exploratory and development wells. This seismic processing combined with seismic pore pressure prediction has allowed us to increase our confidence in well planning and drilling of wells that are deeper and larger in our Southeast Louisiana and South Louisiana areas. The improved seismic image in our Southeast Louisiana and South Louisiana core areas described above has delivered additional high value prospects which could be drilled later this year or next depending upon the commodity pricing environment.

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. In the first quarter of 2009, the through-put capacity of this facility was doubled to 20,000 barrels of oil per day and 40 MMCF of natural gas per day. As a result of this expansion, and continued production decline in older portions of the field, production from our SL 212 facility was redirected to Westside. This has resulted in a reduction in lease operating expenses as the Westside facilities are newer and require less maintenance. The expanded capacity at the Westside facilities was also utilized to process production from our SL 18669 #1 (Shasta) well starting in late April 2009.

In the third quarter of 2008, our Bay de Chene field experienced significant damage to its production facilities from Hurricane Gustav, and some production equipment in the field was damaged or destroyed. Also in the third quarter of 2008, Hurricane Ike caused damage to several fields in our South Louisiana core area and our High Island field due to high water levels. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.8 million, and in September 2009 settled our onshore claim relating to Hurricane Ike for a net amount after deductible of $0.8 million. Both of these reimbursements related to both capital costs and lease operating expense, and we have no additional hurricane related claims outstanding.

Repairs to existing infrastructure as well as the installation of new production equipment and structures for our Bay De Chene field were completed in the third quarter of 2009. In previous quarters, since Hurricane Gustav in 2008, only high-pressure natural gas was produced from the field through existing high-pressure natural gas facilities. Oil and low pressure natural gas production was reinstated after repairs and new facilities installations were completed.

Capital Expenditures

Our capital expenditures on a cash flow basis during 2009 were $215.4 million, while our accrual based capital expenditures were $174.6 million, as during the first quarter of 2009 we paid significant accounts payable and accrued capital cost balances incurred prior to year-end 2008. This cash flow basis amount of capital expenditures decreased by $413.0 million as compared to the 2008 period, primarily due to a decrease in our spending on drilling and development, predominantly, in our Southeast Louisiana and South Texas core areas. These 2009 expenditures were primarily funded by $226.2 million of cash provided by operating activities from continuing operations, and $31.1 million from the sale of properties and proceeds from joint ventures.

We currently plan to balance our 2010 accrual based capital expenditures with our 2010 cash flow and cash on hand. Our 2010 capital expenditures are currently budgeted at $300 million to $375 million, net of minor non-core dispositions and excluding any property acquisitions. These expenditures are expected to include: a continuation of the horizontal well drilling program in the Olmos sands in our AWP field, an ongoing horizontal well program in the Eagle Ford shale formation in the AWP and other South Texas areas, continuing our drilling activity in Lake Washington by targeting shallow and intermediate depth oil prospects, continuing the recompletion program in our Southeast Louisiana core area and the fracture enhancement program in our South Texas core area.

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

In 2009, the Company took several steps to manage lower cash flow and provide liquidity in future periods including:

- Raised $108.8 million, after deducting commissions and offering costs, through an underwritten public stock offering in August 2009. We used the proceeds from this stock sale to pay down a portion of the outstanding balance on our credit facility.
    - Issued $225.0 million of senior notes due 2020 (issued at 98.389% of par) in November 2009 in order to redeem all of our $150 million of senior notes due 2011 in December 2009.
- Reduced 2009 capital expenditures when compared to our 2008 total capital costs incurred of $674.7 million (including acquisitions). We spent $215.4 million in 2009, which was below our cash provided by operating

activities.

- Reduced our workforce. In early 2009, we reduced our workforce, in response to the change in our level of operational activity, which will lower general and administrative costs in future periods.
- Reduced our field lease operating expenses.
- Re-determined our bank credit facility. Our borrowing base and commitment amount in November 2009 was re-set at $277.5 million, a decrease from our previous borrowing base and commitment amount of $300 million.

Results of Continuing Operations — Years Ended 2009, 2008, and 2007

Revenues. Our revenues in 2009 decreased by 55% compared to revenues in 2008 primarily due to lower oil and gas prices as well as decreased production from our Southeast Louisiana core area. Our revenues in 2008 increased by 25% compared to 2007 revenues due to higher oil and gas prices partially offset by decreased production from our Southeast Louisiana core area. Revenues for 2009, 2008, and 2007 were substantially comprised of oil and gas sales. Crude oil production was 48% of our production volumes in 2009, 54% in 2008, and 66% in 2007. Natural gas production was 39% of our production volumes in 2009, 34% in 2008, and 26% in 2007. The remaining production in each year was from natural gas liquids (NGLs).

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 and Chunchula fields. The South Louisiana core area includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, Bayou Penchant fields and High Island. The South Texas core area includes the AWP, Briscoe Ranch, Las Tiendas, and Sun TSH fields. We also have a Strategic Growth category for our other strategic fields. The following table provides information regarding the changes in the sources of our oil and gas production and volumes for the years ended December 31, 2009, 2008, and 2007:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2009	2008	2007	2009	2008	2007
S. E. Louisiana	$232.5	$486.4	$477.0	4,782	5,323	7,178
South Texas	77.4	158.6	72.0	2,721	2,793	1,517
Central Louisiana / E. Texas	37.0	84.7	48.7	864	1,034	872
South Louisiana	24.1	61.6	50.2	660	850	961
Strategic Growth	0.7	2.6	5.0	28	49	89
Total	$371.7	$793.9	$652.9	9,055	10,049	10,617

Our 2008 production was adversely affected by Hurricanes Gustav and Ike. As a result of these hurricanes, approximately 0.8 MMBoe of production was shut-in during 2008 predominantly in Southeast Louisiana. All of this shut-in production was brought online in 2009.

Oil and gas sales in 2009 decreased by 53%, or $422.1 million, from the level of those revenues for 2008, and our net production volumes in 2009 decreased by 10%, or 1.0 MMBoe, over net production volumes in 2008. Average prices for oil decreased to $60.07 per Bbl in 2009 from $101.38 per Bbl in 2008. Average natural gas prices decreased to $3.48 per Mcf in 2009 from $8.54 per Mcf in 2008. Average NGL prices decreased to $31.36 per Bbl in 2009 from $57.15 per Bbl in 2008.

In 2009, our $422.1 million decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $317.2 million unfavorable impact on sales, of which $179.5 million was attributable to the 43% decrease in average oil prices received, $30.5 million was attributable to the 45% decrease in NGL prices, and $107.2 million was attributable to the 59% decrease in average natural gas prices received; and

- Volume variances that had a $104.9 million unfavorable impact on sales, with $108.9 million of decreases attributable to the 1.1 million Bbl decrease in oil production volumes, with $1.6 million of decreases attributable to the less than 0.1 million Bbl decrease in NGL production volumes, partially offset by an increase of $5.6 million due to the 0.7 Bcf increase in natural gas production volumes.

Oil and gas sales in 2008 increased by 22%, or $141.0 million, from the level of those revenues for 2007, and our net production volumes in 2008 decreased by 5%, or 0.6 MMBoe, over net production 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 production volumes, partially offset by both an increase of $21.7 million due to the 0.4 million Bbl increase in NGL production volumes, and an increase of $23.9 million due to the 3.7 Bcf increase in natural gas production volumes.

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

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
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
2009:							
First	1,108	307	5.7	2,366	$41.15	$22.52	$4.19
Second	1,026	308	5.5	2,255	$55.42	$28.26	$3.11
Third	1,078	279	5.2	2,219	$68.15	$35.09	$2.84
Fourth	1,134	289	4.8	2,215	$75.09	$40.45	$3.75
Total	4,346	1,183	21.2	9,055	$60.07	$31.36	$3.48

During 2009, 2008, and 2007, we recognized net gains (losses) of ($1.4) million, $26.1 million, and $0.2 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of operations. Had these gains been recognized in the oil and gas sales account, our average oil sales price would have been $59.77, $105.32 and $71.91 for 2009, 2008, and 2007, respectively, and our average natural gas price would have been $3.47, $8.77 and $6.43 for 2009, 2008, and 2007, respectively.

Costs and Expenses. Our expenses in 2009 decreased $798.5 million, or 65%, compared to 2008 expenses for the reasons noted below.

Our 2009 general and administrative expenses, net, decreased $4.6 million, or 12%, from the level of such expenses in 2008, while 2008 general and administrative expenses, net, increased $4.5 million, or 13%, over 2007 levels. The decrease in 2009 was primarily due to lower stock compensation and lower salaries from the workforce reduction in early 2009, partially offset by lower capitalized amounts. The increase in 2008 was primarily due to increased salaries and burdens associated with our expanded workforce, but was also impacted by increased restricted stock grants. For the years 2009, 2008, and 2007, our capitalized general and administrative costs totaled $24.5 million, $30.1 million, and $26.4 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.76 per Boe in 2009 from $3.85 per Boe in 2008, compared to $3.22 per Boe in 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $11.4 million for 2009, $15.8 million for 2008, and $11.8 million for 2007.

DD&A decreased $56.2 million, or 25%, in 2009, from 2008 levels and increased $33.9 million, or 18% in 2008, from 2007 levels. The decrease in 2009 was due to the write-down of oil and gas properties in the first quarter of 2009 which lowered our depletable base in addition to lower production, partially offset by lower reserves volumes and higher future development costs. 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. Industry costs for goods and services increased from 2007 to 2008 and contributed to the increase in our DD&A expense for those years. Our DD&A rate per Boe of production was $18.34 in 2009, $22.12 in 2008, and $17.74 in 2007, resulting from decreases in per unit cost of reserves additions in 2009 and increases in per unit costs for 2008 and 2007.

We recorded $2.9 million, $2.0 million, and $1.4 million of accretion to our asset retirement obligation in 2009, 2008, and 2007, respectively.

Our lease operating costs decreased $28.1 million, or 27%, compared to the level of such expenses in 2008, while 2008 costs increased $34.0 million, or 48% over 2007 levels. Lease operating costs decreased during 2009 due to decreases in work-over costs, decreasing costs for industry goods and services, as well as lower natural gas and NGL processing costs. These costs increased in 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. Our lease operating costs per Boe produced were $8.47, $10.44, and $6.68 in 2009, 2008, and 2007, respectively.

Severance and other taxes decreased $39.1 million, or 49%, from 2008 levels, while in 2008 these taxes increased $6.6 million, or 9%, over 2007 levels. The decreases in 2009 were due primarily to lower commodity prices and lower production. In 2008 they were caused by higher commodity prices, offset slightly by lower production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.1%, 10.1% and 11.3% in 2009, 2008 and 2007, respectively. The increase in 2009 was caused by an increase in rates on Louisiana natural gas, which increased approximately 10% per Mcf produced, along with a slight increase in total revenues from oil production.

Our total interest cost in 2009 was $36.8 million, of which $6.1 million was capitalized. 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. Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004 and retired in December 2009, including amortization of debt issuance costs, totaled $11.4 million in 2009 and $12.0 million in both 2008 and 2007. 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. 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 both 2009 and 2008. Interest expense on our 8-7/8% senior notes due 2020 and issued in November 2009, including amortization of debt issuance costs and debt discount, totaled $2.0 million in 2009. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $5.2 million in 2009, $8.6 million in 2008, and $6.1 million in 2007. Other interest cost was $0.1 million in each of 2009, 2008 and 2007. We capitalize a portion of interest related to unproved properties. The decrease in interest expense in 2009 was primarily due to a decrease in borrowings against our line of credit facility during the year.

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 2009 we incurred $4.0 million of debt retirement costs related to the redemption of our 7-5/8% senior notes due 2011. The costs were comprised of approximately $2.9 million of premiums paid to repurchase the notes, and $1.1 million to write-off unamortized debt issuance costs.

In the first quarter of 2009, as a result of low oil and gas prices at March 31, 2009 we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and natural gas properties. 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 39.5% for 2009, 37.7% for 2008, and 37.6% for 2007. The effective tax rate for 2009, 2008, and 2007 was higher than the statutory rate primarily because of state income taxes. Valuation allowances also contributed to the 2007 effective rates.

Loss from Continuing Operations. Our loss from continuing operations for 2009 of $39.1 million was significantly lower than our 2008 loss from continuing operations of $257.1 million, due to the write-down of oil and gas properties in the fourth quarter of 2008, partially offset by lower oil and gas sales in 2009.

Our 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.

Net Loss. Our net loss in 2009 of $39.3 million was significantly less than our 2008 net loss of $260.5 million, due to the write-down of oil and gas properties in December 2008, partially offset by lower oil and gas sales.

Our net 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, partially offset by higher oil and gas sales.

Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of operations 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 nine 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. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending final resolution of this litigation.

In accordance with guidance contained in FASB ASC 360-10 (formerly SFAS No. 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 consolidated balance sheets. During 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 a non-cash asset write-down of $3.6 million related to these assets. This write-down is recorded in “Loss from discontinued operations, net of taxes” on the accompanying consolidated statements of operations.

The following table summarizes the amounts included in 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):

	2009	2008	2007
Oil and gas sales	$---	$14,675	$42,394
Other revenues	26	832	1,221
Total revenues	$26	15,507	43,615
Depreciation, depletion, and amortization	---	4,857	23,147
Other operating expenses	280	10,750	22,491
Non-cash write-down of property and equipment	---	3,572	143,152
Total expenses	$280	19,179	188,790
Loss from discontinued operations before income taxes	(254)	(3,672)	(145,175)
Income tax benefit	---	312	13,874
Loss from discontinued operations, net of taxes	$(254)	$(3,360)	$(131,301)
Loss per common share from discontinued operations-diluted	$(0.01)	$(0.11)	$(4.29)
Sales volumes (MBoe)	---	415	1,387
Cash flow provided by (used in) operating activities	$(396)	$6,039	$25,620
Capital expenditures	$---	$1,273	$9,466

Loss from discontinued operations, net of tax, for 2009 decreased compared to 2008 as the majority of our assets were sold in 2008 and day to day operations ceased. Our loss from discontinued operations, net of tax, for 2008 increased compared to 2007 as the majority of our assets were sold in 2008. Our capitalized general and administrative expenses were immaterial for 2009 and 2008 with $4.2 million for 2007.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and over the last year that volatility has increased to extreme levels, and this volatility is expected to continue for 2010 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 first quarter of 2009, however, oil prices made some improvement in the later part 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 continued to fall throughout 2009, showing slight improvement in late 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 owner's 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 2009 and 2008 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 2009 and 2008, oil and gas sales to Shell Oil Corporation and affiliates were 48% and 28% of total oil and gas sales, respectively; Chevron Corporation and its affiliates accounted for 25% of our 2008 total oil and gas sales. 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.

As of December 31, 2009 we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Liquidity and Capital Resources

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

2009 Public Stock Offering. We raised $108.8 million through an underwritten public stock offering in August 2009. We issued 6.21 million shares of our common stock at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million. We used the proceeds from this stock sale to pay down a portion of the outstanding balance on our credit facility.

2009 Debt Issuance and Debt Retirements. We issued $225.0 million of 8-7/8% senior notes due 2020 at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%, in November 2009. The discount of $3.6 million is recorded against “Long-Term Debt” on our balance sheet and will be amortized over the life of the note. In December 2009, we redeemed all $150.0 million of 7-5/8% senior notes due 2011 and recorded a charge of $4.0 million related to the redemption of these notes, which is recorded in “Debt retirement costs” on the accompanying consolidated statement of operations. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

Net Cash Provided by Operating Activities. For 2009, our net cash provided by operating activities from continuing operations was $226.2 million, representing a 61% decrease as compared to $582.0 million generated during 2008. The $355.9 million decrease in 2009 was primarily due to a decrease of $450.4 million in revenues, mainly attributable to lower oil and natural gas prices as well as lower production, partially offset by lower lease operating costs and severance taxes due to lower oil and gas sales. 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.

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, 2009 and 2008, 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 consolidated balance sheets.

Existing Credit Facility. We had no borrowings under our bank credit facility at December 31, 2009, and $180.7 million in borrowings at December 31, 2008. Our bank credit facility at December 31, 2009 consisted of a $500.0 million credit facility with a syndicate of ten banks, and expires in October 2011.

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 2010 and future periods. 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. 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. In November 2009, the borrowing base and commitment amount were re-set at $277.5 million, a reduction from previous levels due to the issuance of our Senior Notes due 2020. The next scheduled borrowing base review is May 2010, and it is possible the borrowing base and commitment amounts could be reduced due to lower oil and gas prices and the then current state of the financial and credit markets.

Debt Maturities. Our credit facility, which had no balance at December 31, 2009, extends until October 3, 2011. Our $250.0 million of 7-1/8% senior notes mature June 1, 2017, and our $225.0 million of 8-7/8% senior notes mature January 15, 2020

Working Capital. Our working capital increased from a deficit of $75.4 million at December 31, 2008, to a surplus of $5.0 million at December 31, 2009. The increase primarily resulted from a decrease in accrued capital costs and an increase in cash and cash equivalents at December 31, 2009 due to proceeds received from the issuance of our new senior notes due 2020, less the amounts used to redeem our senior notes due 2011.

Cash Used in Investing Activities. In 2009 our oil and gas property additions were $215.4 million. This amount decreased by $413.0 million, as compared to additions in 2008, primarily due to a decrease in our spending on drilling and development, predominantly in our Southeast Louisiana and South Texas core areas. These cash based amounts were significantly higher than accrual based capital expenditures as we paid significant accounts payable and accrued capital cost balances incurred prior to year-end 2008. These 2009 expenditures were primarily funded by $226.2 million of cash provided by operating activities from continuing operations, and $31.1 million from the sale of properties and proceeds from joint ventures.

These investing activities included drilling twenty wells during 2009. Four out of five development wells and one of two exploratory wells drilled in the Southeast Louisiana core area were completed while the one development well and one exploratory well were unsuccessful, and thirteen development wells were drilled in the South Texas core area.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2009 are as follows:

	2010	2011	2012	2013	2014	Thereafter	Total
				(in thousands)			
Non-cancelable operating leases (1)	$6,959	$5,665	$5,567	$5,520	$5,532	$922	$30,165
Asset retirement obligation (2)	8,938	1,810	1,689	1,575	1,469	48,755	64,236
Drilling rigs, seismic services, and pipe inventory	3,885	—	—	—	—	—	3,885
7-1/8% senior notes due 2017 (3)	—	—	—	—	—	250,000	250,000
8-7/8% senior notes due 2020 (3)	—	—	—	—	—	225,000	225,000
Credit facility (4)	—	—	—	—	—	—	—
Total	$19,782	$7,475	$7,256	$7,095	$7,001	$524,677	$573,286

(1) Our most significant office lease is in Houston, Texas and it extends until 2015.
(2) Amounts shown by year are the net present value at December 31, 2009.
(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 2009, our proved reserves were 112.9 MMBoe with a PV-10 Value of $1.3 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 2009, our proved natural gas reserves decreased 1.8 Bcf, or 1%, while our proved oil reserves decreased 5.2 MMBbl, or 10%, and our NGL reserves increased 2.0 MMBbl, or 11%, for a total equivalent decrease of 3.5 MMBoe, or 3%. 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%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 8.5 MMBoe of proved reserves in 2009, 5.7 MMBoe in 2008, and 12.9 MMBoe in 2007. Through acquisitions we added no reserves in 2009, 1.0 MMBoe of proved reserves in 2008 and 12.9 Bcfe in 2007. At year-end 2009, 50% of our total proved reserves were proved developed, compared with 53% at year-end 2008 and 48% at year-end 2007.

All of the 8.5 MMboe of proved reserves added through drilling during 2009 were in our AWP field. These additions were primarily proved undeveloped additions based on the results of the horizontal drilling program conducted in the area during the year and would have been recorded as reserves additions under both the former and revised SEC reserves regulations. We obtained reasonable certainty regarding these reserves additions by applying the same methodologies that have been used historically in this field. We did not record material proved reserves additions during 2009 as a result of the revised SEC reserves regulations.

For financial statements issued on or after January 1, 2010. The SEC changed its accounting guidelines for estimates of proved reserves. Estimates must now 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. Previous estimates were made using year-end oil and gas sales prices that were held constant for that year's reserves calculation throughout the life of the properties.

The PV-10 Value of our domestic proved reserves at year-end 2009 increased 1% from the PV-10 Value at year-end 2008. Our average natural gas price used in the PV-10 calculation for 2009 was $3.78 per Mcf. This average price during 2009 was a decrease from $4.96 per Mcf at year-end 2008, compared to $6.65 per Mcf at year-end 2007. Our average oil price used in the PV-10 calculation for 2009 was $59.76 per Bbl. This average price during 2009 was an increase from $44.09 per Bbl at year-end 2008, compared to $93.24 in 2007.

Reserves Estimation. Uncertainties in this calculation stem from the estimating process related to quantities of proved oil and natural gas reserves and the present value of estimated future net cash flows. Proved reserves are quantities of hydrocarbons to be recovered in the future from underground oil and natural gas accumulations that cannot be directly measured in an exact way. Therefore, reserve estimates are made from gathered data of imperfect accuracy and are subject to the same uncertainties inherent in that data. Accordingly, reserves estimates may be different from the quantities of oil and natural gas ultimately recovered.

Income Taxes

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. Under guidance contained in FASB ASC 740-10 (formerly SFAS No. 109), 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.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25 (formerly FASB Interpretation No. 48). Under this guidance, 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 this guidance on January 1, 2007, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. During 2009 we recognized a tax benefit and reduced other long-term liabilities by $0.3 million to reverse an accrual for penalty and interest that was originally recorded in the fourth quarter of 2008. Our current balance of unrecognized tax benefits is $1.0 million. If recognized, these tax benefits would fully impact our effective tax rate. This benefit is likely to be recognized within the next 12 months based on expiration of the audit statutory period.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2009, we do not have any amount accrued for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns for 2002, 2003 and 2006 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position

As of December 31, 2008 the Company had a deferred tax asset of $1.1 million for a capital loss carryforward that was fully offset by a valuation allowance. In the fourth quarter of 2009 the Company reversed this valuation allowance as it was able to utilize this loss carryover to offset a tax gain realized on a joint venture transaction that closed in December of 2009.

Critical Accounting Policies and New Accounting Pronouncements

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 including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. 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. This calculation is done on a country-by-country basis.

The costs of unproved properties not being amortized are 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. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. 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.

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, 2009 that would materially affect this calculation.

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. See the discussion above related to reserves estimation.

In 2009, as a result of lower oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and gas properties. In the fourth quarter of 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 gas properties due to lower oil and natural gas prices at the end of 2008.

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 continue to 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 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."

New Accounting Pronouncements. In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic 932 ("Extractive Industries – Oil and Gas") with the requirements of SEC release 33-8995. These releases are effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. 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 reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-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 is 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 for Form 10K.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

The change in prices used to calculate reserves did not have a material impact upon our reserves estimation in the current period. The new rule requiring the preceding 12-month's average price for oil and natural gas resulted in a lower average price for our reserves calculations for 2009 than if we had used the previous method utilizing the current price at period-end. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

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 $0.6 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2009, $0.7 million in 2008 and $0.6 million in 2007. 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 half of 2008, and such pricing volatility has continued in 2009 with some improvement in the second half of 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 Collars – At December 31, 2009 we had in place price collars in effect for the January through the March 2010 contract months for natural gas. The natural gas price collars cover notional volumes of 200,000 MMBtu per month with a weighted average floor price of $4.50 per MMBtu and notional volumes of 100,000 MMBtu per month at a weighted average cap price of $6.80 per MMBtu. The fair value of these instruments at December 31, 2009 was an asset of less than $0.1 million and is recognized on the accompanying balance sheet in "Other current assets." There may be additional cash outflows for these price collars, as no cash premium was paid at inception of the hedge. It is possible that we may recognize a loss on our statement of operations from these price collars during the first quarter of 2010 though the amount is unknown due to the variability of natural gas prices.

Price Floors – Between October and December 2009 we entered into additional price floors. These floors cover additional natural gas production of 2,400,000 MMBtu from January through March 2010 and 2,640,000 MMBtu from April through June 2010 with strike prices ranging between $4.55 and $4.96.

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, 2009, we had no borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 43 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, 2009, the Company has net tax carryforwards assets of $21.3 million for federal net operating losses, $5.4 for federal alternative minimum tax credits and $8.3 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.

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, 2009 the estimated U.S. dollar value of these loss carryover assets is $32.0 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, 2009 and 2008, 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, 2009 and 2008, the fair value of our senior notes due

2017, were $239.1 million, or 96% of face value, and $175.0 million, or 70% of face value, respectfully. Based upon quoted market prices as of December 31, 2009, the fair values of our senior notes due 2020 were $234.0 million, or 104% of face value. Based upon quoted market prices as of December 31, 2008, the fair values of our senior notes due 2011 were $132.8 million, or 88.5% of face value. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2009 and 2008. The carrying value of our senior notes due 2020 was $221.4 million at December 31, 2009. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2008.

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

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, 2009. 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, 2009.

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, 2009, 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, 2009, 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 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, 2009, 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, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 25, 2010 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 25, 2010

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, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.
As discussed in Note 1 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2009, 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, 2010 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 25, 2010

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

	Year Ended December 31,	
	2009	2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$38,469	$283
Accounts receivable-		
Oil and gas sales	36,343	37,364
Joint interest owners	2,590	4,235
Other Receivables	15,340	20,065
Deferred tax assets	3,171	---
Other current assets	12,123	15,575
Current assets held for sale	564	564
Total Current Assets	108,600	78,086
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	3,421,340	3,270,159
Unproved properties	71,640	91,252
	3,492,980	3,361,411
Furniture, fixtures, and other equipment	37,130	37,669
	3,530,110	3,399,080
Less – Accumulated depreciation, depletion, and amortization	(2,214,146)	(1,967,633)
	1,315,964	1,431,447
Other Assets:		
Deferred Charges	8,836	6,107
Other Long-Term assets	1,365	1,648
	10,201	7,755
	$1,434,765	$1,517,288
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$60,823	$66,802
Accrued capital costs	33,199	74,315
Accrued interest	3,745	7,207
Undistributed oil and gas revenues	5,837	5,175
Total Current Liabilities	103,604	153,499
Long-Term Debt	471,397	580,700
Deferred Income Taxes	123,577	130,899
Asset Retirement Obligation	55,298	48,785
Other Long-Term Liabilities	1,990	2,528
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, 37,887,126 and 31,336,472 shares issued, and 37,456,603 and 30,868,588 shares outstanding respectively	379	313
Additional paid-in capital	551,606	435,307
Treasury stock held, at cost, 430,523 and 467,884 shares, respectively	(9,221)	(10,431)
Retained earnings	136,358	175,688
Accumulated other comprehensive loss, net of income tax	(223)	---
	678,899	600,877
	$1,434,765	$1,517,288

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2009	2008	2007
Revenues:			
Oil and gas sales	$371,749	$793,859	$652,856
Price-risk management and other, net	(1,304)	26,956	1,265
	370,445	820,815	654,121
Costs and Expenses:			
General and administrative, net	34,046	38,673	34,182
Depreciation, depletion, and amortization	166,108	222,288	188,393
Accretion of asset retirement obligation	2,906	1,958	1,437
Lease operating cost	76,740	104,874	70,893
Severance and other taxes	41,326	80,403	73,813
Interest expense, net	30,663	31,079	28,082
Debt retirement cost	3,961	---	12,765
Write-down of oil and gas properties	79,312	754,298	---
	435,062	1,233,573	409,565
Income (Loss) from Continuing Operations Before Income Taxes	(64,617)	(412,758)	244,556
Provision (Benefit) for Income Taxes	(25,541)	(155,628)	91,968
Income (Loss) from Continuing Operations	(39,076)	(257,130)	152,588
Loss from Discontinued Operations, net of taxes	(254)	(3,360)	(131,301)
Net Income (Loss)	$(39,330)	$(260,490)	$21,287
Per Share Amounts-			
Basic: Income (Loss) from Continuing Operations	$(1.16)	$(8.39)	$5.09
Loss from Discontinued Operations, net of taxes	(0.01)	(0.11)	(4.38)
Net Income (Loss)	$(1.17)	$(8.50)	$0.71
Diluted: Income (Loss) from Continuing Operations	$(1.16)	$(8.39)	$4.98
Loss from Discontinued Operations, net of taxes	(0.01)	(0.11)	(4.29)
Net Income (Loss)	$(1.17)	$(8.50)	$0.69
Weighted Average Shares Outstanding	33,594	30,661	29,984

See accompanying notes to consolidated financial statements.

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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	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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
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
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
	-	(716)	2,094	-	-	1,378

Stock issued for benefit plans (94,023 shares)						
Stock options exercised (26,056 shares)	-	326	-	-	-	326
Public Stock offering (6,210,000 shares)	62	108,689	-	-	-	108,751
Purchase of treasury shares (56,662 shares)	-	-	(884)	-	-	(884)
Tax benefits from stock compensation	-	(4,041)	-	-	-	(4,041)
Employee stock purchase plan (50,690 shares)	1	724	-	-	-	725
Issuance of restricted stock (263,908 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	11,320	-	-	-	11,320
Net loss	-	-	-	(39,330)	-	(39,330)
Other comprehensive income (loss)	-	-	-	-	(223)	(223)
Total comprehensive loss						(39,553)
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$ (223)	$678,899

(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,		
	2009	2008	2007
Cash Flows from Operating Activities:			
Net income (loss)	$(39,330)	$(260,490)	$21,287
Plus loss from discontinued operations, net of taxes	254	3,360	131,301
Adjustments to reconcile net income (loss) to net cash provided by operation activities -			
Depreciation, depletion, and amortization	166,108	222,288	188,393
Write-down of oil and gas properties	79,312	754,298	---
Accretion of asset retirement obligation	2,906	1,958	1,437
Deferred income taxes	(13,377)	(164,498)	86,474
Stock-based compensation expense	9,232	11,631	10,317
Debt retirement cost – cash and non-cash	3,961	---	12,765
Other	16,133	(8,640)	(4,314)
Change in assets and liabilities-			
(Increase) decrease in accounts receivable	2,666	26,172	(9,114)
Increase (decrease) in accounts payable and accrued liabilities	1,977	(3,915)	5,748
Increase (decrease) in income taxes payable	(204)	214	(806)
Decrease in accrued interest	(3,462)	(351)	(1,206)
Cash Provided by operating activities – continuing operations	226,176	582,027	442,282
Cash Provided by (Used in) operating activities – discontinued operations	(396)	6,039	25,620
Net Cash Provided by Operating Activities	225,780	588,066	467,902
Cash Flows from Investing Activities:			
Additions to property and equipment	(215,370)	(628,325)	(398,295)
Proceeds from the sale of property and equipment	31,083	144	250
Acquisition of properties	---	(46,472)	(252,299)
Net cash received as operator of partnerships and joint ventures	---	---	485
Cash Used in investing activities – continuing operations	(184,287)	(674,653)	(649,859)
Cash Provided By (Used in) investing activities – discontinued operations	5,000	80,504	(7,827)
Net Cash Used in Investing Activities	(179,287)	(594,149)	(657,686)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	221,375	---	250,000
Payments of long-term debt	(150,000)	---	(200,000)
Net proceeds from (payments of) bank borrowings	(180,700)	(6,300)	155,600
Net proceeds from issuances of common stock	109,801	9,243	3,789
Excess tax benefits from stock-based awards	---	1,422	613
Purchase of treasury shares	(884)	(3,622)	(1,826)
Payments of debt retirement costs	(2,859)	---	(9,376)
Payments of debt issuance costs	(5,040)	---	(4,451)
Cash provided by financing activities – continuing operations	(8,307)	743	194,349
Cash provided by financing activities – discontinued operations	---	---	---
Net Cash Provided by (Used in) financing activities	(8,307)	743	194,349

Net Increase (Decrease) in Cash and Cash Equivalents	$38,186	$(5,340)	$4,565
Cash and Cash Equivalents at Beginning of Year	283	5,623	1,058
Cash and Cash Equivalents at End of Year	$38,469	$283	$5,623
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$32,885	$30,283	$28,092
Cash paid during year for income taxes	$233	$8,505	$2,113

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 and facilities are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Discontinued Operations. Unless otherwise indicated, information presented in the notes to the financial statements relates only to Swift Energy'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.

Subsequent Events. We have evaluated subsequent events through the time of filing on February 25, 2010 of our consolidated financial statements. There were no other material subsequent events requiring additional disclosure in or amendments to these financial statements as of February 25, 2010.

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 2009, 2008, and 2007, such internal costs capitalized totaled $24.5 million, $30.1 million, and $26.4 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2009, 2008, and 2007, capitalized interest on unproved properties totaled $6.1 million, $8.0 million, and $9.5 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 are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between 2 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”). Our hedges at year-end 2009 consisted of natural gas collars and price floors with strike price ranges outside the current period-end price and did not affect prices used in these calculations. This calculation is done on a country-by-country basis.

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 2009, as a result of low oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million on our oil and natural gas properties. For 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a fourth quarter 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 continue to 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, 2009, 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.

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, 2009 and 2008, 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, 2009 and 2008, the fair value of our senior notes due 2017, were $239.1 million, or 95.6% of face value, and $175.0 million, or 70.0% of face value, respectfully. Based upon quoted market prices as of December 31, 2009, the fair values of our senior notes due 2020, which were issued in November 2009, was $234.0 million, or 104% of face value. Based upon quoted market prices as of December 31, 2008, the fair values of our senior notes due 2011, which were redeemed in December 2009, were $132.8 million, or 88.5% of face value. The carrying value of our senior notes due 2017 were $250.0 million at December 31, 2009 and 2008, while the carrying value of our senior notes due 2020 was $221.4 million at December 31, 2009.

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, 2009 and 2008, 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 fees, 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 2007 of our 7-1/8% senior subordinated notes due 2017 and the public offering in November 2009 of our 8-7/8% senior subordinated notes due 2020 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, 2009, was $3.4 million, net of accumulated amortization of $0.8 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at December 31, 2009, was $5.0 million, net of accumulated amortization of less than $0.1 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, 2009, was $0.5 million, net of accumulated amortization of $2.8 million.

Insurance Claims. In 2008, we filed insurance claims related to 2008 Hurricanes Gustav and Ike. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.8 million, and in September 2009 settled our onshore claim relating to Hurricane Ike for a net amount after deductible of $0.8 million. Both of these reimbursements related to both capital costs and lease operating expense, and we have no additional hurricane related claims outstanding.

We have several open insurance claims filed in the ordinary course of business, none of which are material at the present time.

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Price-Risk Management Activities. The Company follows FASB ASC 815-10 (formerly SFAS No. 133), which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance 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 statement of operations 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 natural gas prices, mainly through the purchase of price floors and collars. During 2009, 2008, and 2007, we recognized net gains (losses) of ($1.4) million, $26.1 million, and $0.2 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations. 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, 2009, the Company had recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying consolidated 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 the twelve months of 2009 and 2008 was not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next six months when the forecasted sale of hedged production occurs.

At December 31, 2009, we had natural gas price collars in effect for the contract months of January through March 2010 that covered a portion of our natural gas production for January to March 2010. The natural gas price collars contain a floor that covers notional volumes of 200,000 MMBtu per month and a call that covers 100,000 MMBtu per month, for the same period. The weighted average floor price is $4.50 and the weighted average call price is $6.80 per MMBtu. At December 31, 2009, we had natural gas price floors in effect for the contract months of January through June 2010 that covered a portion of our natural gas production for January to June 2010. These floors cover additional natural gas production of 2,400,000 MMBtu from January through March 2010 and 2,640,000 MMBtu from April through June 2010 with strike prices ranging between $4.55 and $4.96.

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 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 loss, net of income tax" and recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2009, was $0.8 million and was recognized on the accompanying consolidated balance sheet in "Other current assets." At December 31, 2008, we had $11.8 million in receivables for concluded oil hedges covering 2008 production which were 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 2009 and 2008 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $11.4 million in 2009, $15.8 million in

2008, and $11.8 million in 2007.

Inventories. We value inventories at the lower of cost or market value. Inventory is accounted for using the weighted average cost method. Inventories consisting of materials, supplies, and tubulars are included in “Other current assets” on the accompanying consolidated balance sheets totaling $10.0 million at December 31, 2009 and $13.7 million at December 31, 2008. In the third quarter of 2009 we wrote down our inventory balance by approximately $0.5 million due to expected lower net realizable values for certain tubulars. This write-down was recorded in “Price-risk management and other, net” on the accompanying consolidated statement of operations

Income Taxes. Under guidance contained in FASB ASC 740-10 (formerly SFAS No. 109), 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.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25 (formerly FASB Interpretation No. 48), Under this guidance, 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 this guidance on January 1, 2007, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. During 2009 we recognized a tax benefit and reduced other long-term liabilities by $0.3 million to reverse an accrual for penalty and interest that was originally recorded in the fourth quarter of 2008. Our current balance of unrecognized tax benefits is $1.0 million. If recognized, these tax benefits would fully impact our effective tax rate. This benefit is likely to be recognized within the next 12 months due to expiration of the audit statutory period.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2009, we did not have any amount accrued for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns for 2002, 2003 and 2006 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. Included in “Accounts payable and accrued liabilities,” on the accompanying consolidated balance sheets, at December 31, 2009 and 2008 are liabilities of approximately $7.5 million and $23.5 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 owner’s 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 2009 and 2008, oil and gas sales to Shell Oil Company and affiliates accounted for 48% and 28% of our gross receipts, respectively. During 2008 sales to Chevron Corporation and its affiliates accounted for 25% of our total oil and gas receipts. Credit losses in each of the last three years were immaterial.

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. These assets include approximately $1.3 million in other long-term assets on the balance sheet. 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.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10 (formerly SFAS No. 130), 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, 2009, we recorded $0.2 million, net of taxes of less than $0.1 million, of derivative losses in “Accumulated other comprehensive loss, net of income tax” on the accompanying consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2009 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2008	$---	$---	$---
Change in fair value of cash flow hedges	(1,311)	484	(827)
Effect of cash flow hedges settled during the period	958	(353)	605
Other comprehensive income (loss) at December 31, 2009	$(354)	$131	$(223)

Total comprehensive income (loss) was ($39.6) million, ($260.1) million and $20.6 million for 2009, 2008, and 2007, respectively.

Asset Retirement Obligation. We record these obligations in accordance with the guidance contained in FASB ASC 410-20 (formerly SFAS No. 143), this guidance 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 expected date of abandonment. 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 guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

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

Asset Retirement Obligation as of December 31, 2006	$28,793
Accretion expense	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	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
Accretion expense	2,906
Liabilities incurred for new wells and facilities construction	3,400
Liabilities incurred for acquisitions	---
Reductions due to sold and abandoned wells	(1,380)
Revisions in estimated cash flows	10,525
Asset Retirement Obligation as of December 31, 2009	$64,236

At December 31, 2009 and 2008, we had $8.9 million and $0, respectively, of our asset retirement obligation classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets.

Public Stock Offering. In August 2009, we issued 6.21 million shares of our common stock in an underwritten public offering at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million.

New Accounting Pronouncements. In March 2008, the FASB issued guidance contained in FASB ASC 815-10 (formerly SFAS No. 161). This guidance changes the disclosure requirements for derivative instruments and hedging activities. This guidance requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under FASB ASC 815-10 and how derivative instruments and related hedged items affect an entity’s financial position, results of operations, and cash flows. This guidance was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this guidance only impacts disclosure requirements, the adoption of this guidance did not have an impact on our financial position or results of operations.

In June 2008, the FASB issued guidance contained in FASB ASC 260-10 (formerly FASB Staff Position No. EITF 03-6-1). Under the guidance, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. This guidance was adopted on January 1, 2009. The adoption of this guidance did not have a material impact on our financial position, results of operations, or earnings per share.

On January 1, 2009 we adopted the guidance contained in FASB ASC 820-10 (formerly 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. The adoption of this guidance did not have a material impact on our financial position or results of operations.

In May 2009, the FASB issued guidance contained in FASB ASC 855-10 (formerly SFAS No. 165). The guidance establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted the guidance for the period ending June 30, 2009; and the adoption of this guidance did not have an impact on our financial position or results of operations.

In June 2009, the FASB issued guidance now codified as FASB ASC Topic 105, "Generally Accepted Accounting Principles," as the single source of authoritative nongovernmental U.S. GAAP. FASB ASC Topic 105 does not change current U.S. GAAP, but is intended to simplify user access to all authoritative U.S. GAAP by providing all authoritative literature related to a particular topic in one place. All existing accounting standard documents will be superseded and all other accounting literature not included in the FASB Codification will be considered non-authoritative. These provisions of FASB ASC Topic 105 are effective for interim and annual periods ending after September 15, 2009 and, accordingly, are effective for our current fiscal reporting period. The adoption of this pronouncement did not have an impact on the Company's financial position or results of operations, but will impact our financial reporting process by eliminating all references to pre-codification standards. On the effective date of this Statement, the Codification superseded all then-existing non-SEC accounting and reporting standards, and all other non-grandfathered non-SEC accounting literature not included in the Codification became non-authoritative.

In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic 932 ("Extractive Industries – Oil and Gas") with the requirements of SEC release 33-8995. This release is effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. 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 reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-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 is 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.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

The change in prices used to calculate reserves did not have a material impact upon our reserves estimation in the current period. The new rule requiring the preceding 12-month's average price for oil and natural gas resulted in a lower average price for our reserves calculations for 2009 when compared to the previous method which used the current price at period-end. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

As a result of the Company's implementation of the Codification during the quarter ended September 30, 2009, previous references to new accounting standards and literature are no longer applicable. In the current financial statements, the Company will provide reference to both new and old guidance to assist in understanding the impacts of recently adopted accounting literature, particularly for guidance adopted since the beginning of the current fiscal year but prior to the Codification.

2. Earnings Per Share

The Company adopted guidance in FASB ASC 260-10 (formerly FASB Staff Position No. EITF 03-6-1) on January 1, 2009. Under the guidance, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. Unvested share-based payments that contain non-forfeitable rights to dividends or dividend equivalents are now included in the basic weighted average share calculation under the two-class method. These shares were previously included in the diluted weighted average share calculation under the treasury stock method.

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. As we recognized a net loss for the years ended December 31, 2009 an 2008, the unvested share-based payments and stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Diluted EPS for the year ended December 31, 2007 also assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the year ended December 31, 2007, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2009, 2008, and 2007 (in thousands, except per share amounts):

	2009			2008			2007		
	Loss from continuing operations	Shares	Per Share Amount	Loss 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	$(39,076)	33,594		$(257,130)	30,661		$152,588	29,984	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		---	---		(3,150)	---	
Income (Loss) from continuing operations allocated to common shares	$(39,076)	33,594	$(1.16)	$(257,130)	30,661	$(8.39)	$149,438	29,984	$4.98
Dilutive Securities:									
Plus: Income (Loss) from continuing operations allocated to unvested shareholders							3,150		
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders							(3,105)		
Stock Options	--	--		--	--		--	438	

Diluted EPS:									
Net Income (Loss) from continuing operations, and assumed share conversions	$(39,076)	33,594	$(1.16)	$(257,130)	30,661	$(8.39)	$149,483	30,422	$4.91

Options to purchase approximately 1.3 million shares at an average exercise price of $29.72 were outstanding at December 31, 2009, while options to purchase approximately 1.1 million shares at an average exercise price of $33.22 were outstanding at December 31, 2008, and options to purchase 1.4 million shares at an average exercise price of $28.47 were outstanding at December 31, 2007. All of the 1.3 million and 1.1 million stock options to purchase shares outstanding at December 31, 2009 and 2008, respectfully, were not included in the computation of Diluted EPS, 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 year ended December 31, 2007 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 0.7 million and 0.6 million shares of employee restricted stock outstanding at December 31, 2009 and 2008, respectfully, were not included in the computation Diluted EPS, as they would be antidilutive given the net loss from continuing operations. Employee restricted stock grants of 0.4 million shares were not included in the computation of Diluted EPS for the year ended December 31, 2007, 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,		
	2009	2008	2007
Income (Loss) from Continuing Operations Before Income Taxes	$(64,617)	$(412,758)	$244,556

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

	Year Ended December 31,		
	2009	2008	2007
Current:	$(10,792)	$5,923	$6,902
Deferred	(14,749)	(161,551)	85,066
Total	$(25,541)	$(155,628)	$91,968

Current taxes are primarily U.S. Federal income taxes. For 2009 current income tax expense is a net credit due to realization of U.S. Federal income tax refunds that were not anticipated at the end of 2008. These refunds were realized as a result of receiving approval for tax accounting method changes from the Internal Revenue Service and lower than estimated tax preference adjustments for the 2008 U.S. Federal income tax return. The refunds were primarily attributable to reductions in alternative minimum tax previously paid. 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):

	2009	2008	2007
Income taxes computed at U.S. statutory rate (35%)	$(22,616)	$(144,465)	$85,595
State tax provisions (benefits), net of federal benefits	(1,956)	(11,985)	3,396
Cumulative impact of adjustments to net state income tax rate	---	---	---
Write-offs and valuation allowance of carryover tax assets	(1,082)	---	2,585
Other, net	113	822	392
Provision (benefit) for income taxes	$(25,541)	$(155,628)	$91,968
Effective rate	39.5 %	37.7 %	37.6 %

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 were credits of $2.0 million and $12.0 million for 2009 and 2008, respectively, and a charge of $3.4 million for 2007. In 2007 the Company recorded a write-off of $1.5 million and a valuation allowance of $1.1 million related to capital loss carryovers. In 2009 it was able to reverse the $1.1 million valuation allowance as a result of a tax gain realized on a joint venture transaction.

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2009 and 2008 were as follows (in thousands):

	2009	2008
Deferred tax assets:		
Federal net operating losses	$21,283	$15,971
Alternative minimum tax credits	5,364	14,509
Carryover items, net of valuation allowance	9,370	8,034
Unrealized stock compensation	4,861	4,399
Other	6,016	2,977
Total deferred tax assets	$46,894	$45,890
Deferred tax liabilities:		
Oil and gas exploration and development costs	$(165,316)	$(175,108)
Other	(1,984)	(1,681)
Total deferred tax liabilities	$(167,300)	$(176,789)
Net deferred tax liabilities	$(120,406)	$(130,899)
Net current deferred tax assets	3,171	--
Net non-current deferred tax liabilities	$(123,577)	$(130,899)

Deferred tax assets increased by $1 million. The federal net operating loss tax assets increased by $5.3 million due to a current year tax operating loss and a change in tax accounting methods noted previously, and other items (consisting primarily of expenses accrued for books that are not currently deductible for tax) increased by $3.0 million; these increases were offset by the reduction in the alternative minimum tax credits, primarily the result of the Federal income tax refunds noted previously.

The total change in the deferred liability from 2008 to 2009 was a decrease of $9.5 million. This decrease is primarily attributable to a $9.8 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.

The federal net operating losses will expire between 2027 and 2029 if not utilized in earlier periods. The other primary carryover item is an $8.3 million net asset for State of Louisiana net operating loss carryovers. These loss carryforwards are scheduled to expire between 2013 and 2024.

Unrealized stock compensation accounts for $4.9 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.

As of December 31, 2008 the Company had a deferred tax asset of $1.1 million for a capital loss carryforward that was fully offset by a valuation allowance. In the fourth quarter of 2009 the Company was reversed this valuation allowance. When the Company files its 2009 Federal income tax return it will be able to utilize this capital loss carryover to partially offset a tax gain realized on a joint venture transaction that closed in December of 2009.

4. Long-Term Debt

Our long-term debt as of December 31, 2009 and 2008, is as follows (in thousands):

	2009	2008
Bank Borrowings	$---	$180,700
7-5/8% senior notes due 2011	---	150,000
7-1/8% senior notes due 2017	250,000	250,000
8-7/8% senior notes due 2020	221,397	---
Long-Term Debt	$471,397	$580,700

Bank Borrowings. At December 31, 2009 we had no borrowings and as of December 31, 2008 we had borrowings of $180.7 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $277.5 million, and expires in October 2011. In November 2009, the borrowing base and commitment amount were re-set at $277.5 million, a reduction from previous levels due to the issuance of our Senior Notes due 2020. Effective November 1, 2009, the interest rate is either (a) the lead bank's prime rate plus applicable margin or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margins have increased to escalating rates of 100 to 250 basis points above the lead bank's prime rate and escalating rates of 200 to 350 basis points for LIBOR rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At December 31, 2009, the lead bank's prime rate was 4.25%.

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. 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 2010.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5.2 million in 2009, $8.6 million in 2008, and $6.1 million in 2007. The amount of commitment fees included in interest expense, net was $0.7 million in 2009 and $0.5 million in 2008 and 2007.

Senior Notes Due 2020. These notes consist of $225 million of 8-7/8% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%. The notes were issued on November 25, 2009 with a discount of $3.6 million and will mature on January 15, 2020. The discount of $3.6 million is recorded in "Long-Term Debt" on our balance sheet and will be amortized over the life of the note. 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 January 15 and July 15 and commenced on November 25, 2009. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. In addition, prior to January 15, 2013, 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 108.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately

$5.0 million of debt issuance costs related to these notes, which is included in "Other assets – Deferred Charges" 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. 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 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $2.0 million for the year ended December 31, 2009.

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 consolidated 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 for both years ended December 31, 2009 and 2008 compared to $10.6 million for the year ended December 31, 2007.

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 statements of operations. 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.

Senior Notes Due 2011. These notes consisted of $150.0 million of 7-5/8% senior subordinated notes due July 2011, which were issued on June 23, 2004. Interest on these notes was payable semiannually on January 15 and July 15. As of December 10, 2009, we redeemed all $150.0 million of these notes. In the fourth quarter of 2009, we recorded a charge of $4.0 million related to the redemption of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statements of operations. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $11.4 million in 2009 and $12.0 million in 2008 and 2007.

The maturities on our long-term debt are $250.0 million in 2017 and $225.0 million in 2020.

We have capitalized interest on our unproved properties in the amount of $6.1 million, $8.0 million, and $9.5 million, in 2009, 2008, and 2007, respectively.

5. Commitments and Contingencies

Rental and lease expenses which were included in "General and administrative, net" on our accompanying consolidated statements of operations were $4.2 million in 2009, $3.2 million in 2008, and $3.7 million in 2007. Rental and lease expenses which were included in "Lease operating cost" on our accompanying consolidated statements of operations were $10.5 million in 2009, $8.6 million in 2008, and $6.7 million in 2007. Our remaining minimum annual obligations under non-cancelable operating lease commitments were $7.0 million for 2010, $5.7 million for 2011, $5.6 million for 2012, $5.5 million for 2013, $5.5 million for 2014 and $0.9 million thereafter or $30.2 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, 2009 for these services and materials totaled $3.9 million.

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 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. 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, 2006). Under this plan for the last three years, we have issued 50,690 shares at a price of $14.29 in 2009, 25,645 shares at a price of $36.83 in 2008, and 17,678 shares at a price of $35.00 in 2007 and registered 200,000 new shares in 2008. As of December 31, 2009, 141,467 shares remained available for issuance under this plan.

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. 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. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the twelve months ended December 31, 2009, we recognized a tax benefit shortfall of $2.0 million as restricted stock vested at a lower value than the value used to record compensation expense at the date of grant, offset by a reduction to additional paid-in capital. Additionally, we derecognized excess tax benefits credited to additional paid-in capital in 2008 and 2007 of $1.5 million and $0.6 million, respectively. This derecognition was due to lower than estimated taxable income for the 2008 income tax return and utilization of a loss carryback to obtain a partial tax refund for taxes paid in 2007. After these adjustments, no actual cash benefit was realized for the excess tax benefits for vesting of restricted stock and exercise of stock options during these periods. Accordingly, we reduced additional paid-in capital by an additional $2.1 million to derecognize the excess tax benefits previously recorded for these periods.

Net cash proceeds from the exercise of stock options were $0.3 million, $8.3 million, and $3.2 million for the years ended December 31, 2009, 2008, and 2007 respectively. The actual income tax benefit from stock option exercises was $0.1 million, $4.1 million, and $1.9 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 operations, and was $8.4 million, $10.6 million, and $9.4 million for the years ended December 31, 2009, 2008, and 2007, respectively. Stock compensation recorded in lease operating cost was $0.4 million, $0.6 million, and $0.5 million for the years ended December 31, 2009, 2008, and 2007, respectively. We also capitalized $2.1 million, $4.5 million, and $4.2 million of stock compensation in 2009, 2008, and 2007, respectively.

Our shares available for future grant under our stock compensation plans were 1,429,044 at December 31, 2009. 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,					
	2009		2008		2007	
Dividend yield	0	%	0	%	0	%
Expected volatility	50.5	%	39.5	%	38.5	%
Risk-free interest rate	1.8	%	2.4	%	4.7	%
Expected life of options (in years)	4.5		4.1		6.0	
Weighted-average grant-date fair value	$6.32		$15.26		$19.61	

The expected term for grants issued during or after 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 and 2009 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, 2009, there was $1.2 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.0 year. The following table represents stock option activity for the years ended December 31, 2009, 2008 and 2007:

	2009		2008		2007	
	Shares	Wtd Avg. Exer. Price	Shares	Wtd, Avg Exer. Price	Shares	Wtd. Avg Exer. Price
Options outstanding, beginning of period	1,119,469	$33.22	1,449,240	$28.47	1,549,140	$24.59
Options granted	273,400	$14.66	216,315	$46.37	201,691	$43.40
Options canceled	(77,619)	$33.26	(44,289)	$34.69	(41,800)	$37.15
Options exercised1	(26,056)	$12.52	(501,797)	$24.96	(259,791)	$18.13
Options outstanding, end of period	1,289,194	$29.72	1,119,469	$33.22	1,449,240	$28.47

Options exercisable, end of period	790,394	$31.00	649,714	$26.41	967,429	$25.70

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 and 2007, respectively, 81,515 and 19,191 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, 2009 was $5.1 million and 5.3 years and $2.5 million and 3.3 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2009 was $0.2 million.

The following table summarizes information about stock options outstanding at December 31, 2009:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/09	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/09	Wtd. Avg. Exercise Price
$ 8.00 to $24.99	560,799	5.9	$14.94	287,399	$15.20
$25.00 to $44.99	583,804	5.6	$38.27	358,404	$35.00
$45.00 to $65.00	144,591	1.3	$52.48	144,591	$52.48
$ 8.00 to $65.00	1,289,194	5.3	$29.72	790,394	$31.00

Restricted Stock. In 2009, 2008 and 2007, the Company issued 433,210, 314,440 and 329,290 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 $12 per share in 2009, $44 per share in 2008 and $43 per share in 2007.

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, 2009, we have unrecognized compensation expense of approximately $6.6 million associated with these awards which are expected to be recognized over a weighted-average period of 1.5 years. The total fair value of shares vested during the year ended December 31, 2009 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, 2009, 2008, and 2007:

	2009		2008		2007	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg.Grant Price
Restricted shares outstanding, beginning of period	586,325	$42.78	596,590	$41.60	503,184	$40.04
Restricted shares granted	433,210	$12.48	314,440	$43.61	329,290	$43.17
Restricted shares canceled	(51,750)	$41.86	(49,859)	$42.65	(47,595)	$39.63
Restricted shares vested	(263,929)	$42.92	(274,846)	$41.18	(188,289)	$40.05
Restricted shares outstanding, end of period	703,856	$24.15	586,325	$42.78	596,590	$41.60

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 three-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, 2009, 2008, and 2007, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the year ended December 31, 2009, $0.2 million for the year ended December 31, 2008 and $04 million for the year ended December 31, 2007, and were all made in common stock, and are recorded as “General and administrative, net” on the accompanying consolidated statements of operations. The shares of common stock contributed to the ESOP plan totaled 8,347, 11,898, and 9,218 shares for the 2009, 2008, and 2007 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 $1.3 million for 2009, $1.5 million for 2008, and $1.3 million for 2007, and are recorded as “General and administrative, net” on the accompanying consolidated statements of operations. The contributions in 2009, 2008, and 2007 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 50,988, 82,125, and 29,934 shares for the 2009, 2008, and 2007 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, 2009, 430,523 shares remain in treasury (net of 666,680 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $9.2 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 $0.6 million to Tec-Com for such services pursuant to the terms of the contract in 2009, $0.7 million in 2008 and $0.6 million in 2007. 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 have been classified as discontinued operations in the consolidated statements of operations 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 nine 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. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending final resolution of this litigation.

In accordance with guidance contained in FASB ASC 360-10 (formerly SFAS No. 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 consolidated balance sheets. During the first nine months 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 a non-cash asset write-down of $3.6 million related to these assets. This write-down is recorded in "Loss from discontinued operations, net of taxes" on the accompanying consolidated statements of operations.

The book value of our remaining New Zealand permit is approximately $0.6 million at December 31, 2009.

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

	2009	2008	2007
Oil and gas sales	$---	$14,675	$42,394
Other revenues	26	832	1,221
Total revenues	$26	15,507	43,615
Depreciation, depletion, and amortization	---	4,857	23,147
Other operating expenses	280	10,750	22,491
Non-cash write-down of property and equipment	---	3,572	143,152
Total expenses	$280	19,179	188,790
Loss from discontinued operations before income taxes	(254)	(3,672)	(145,175)
Income tax benefit	---	312	13,874
Loss from discontinued operations, net of taxes	$(254)	$(3,360)	$(131,301)
Loss per common share from discontinued operations-diluted	$(0.01)	$(0.11)	$(4.29)
Sales volumes (MBoe)	---	415	1,387
Cash flow provided by operating activities	(396)	6,039	25,620
Capital expenditures	$---	$1,273	$9,466

Our capitalized general and administrative expenses were immaterial in 2009 and 2008 and were $4.2 million in 2007.

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):

	2009	2008	2007
Income (loss) before tax from discontinued operations	$(254)	$(3,672)	$(145,175)
Income taxes computed at U.S. statutory rate (35%)	(89)	(1,285)	(50,811)
Effect of foreign operations	12	973	6,336
Currency exchange impact on foreign tax calculation	(6,377)	---	(1,659)
Valuation allowance	6,454	---	33,502
Other	---	---	(1,242)
Total income tax expense related to discontinued operations	$0	$(312)	$(13,874)
Effective tax rate	0.0%	8.5%	9.6%

There were no significant net deferred assets (liabilities) associated with assets held for sale at December 31, 2009 and 2008.

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, 2009, the U.S. dollar value of the deferred asset was $32.0 million. As of December 31, 2009, 2008 and 2007, 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 net 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, 2009 and 2008 (in thousands):

		2009		2008
ASSETS				
Property and equipment, net	$	564	$	564
Total Current assets held for sale	$	564	$	564
LIABILITIES				
Deferred Revenue (1)	$	5,000	$	---
Total Current liabilities associated with assets held for sale	$	5,000	$	---

(1) Included in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets.

9. Acquisitions and Dispositions

In August 2009, within our Central Louisiana/East Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Burr Ferry field in Vernon Parish, LA. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $4.2 million related to this transaction. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

In November 2009, within our South Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Eagle Ford Shale in McMullen County, TX. The Company, as fee mineral owner leased a 50% working interest in approximately 26,000 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $26 million in cash consideration as well as consideration for approximately $13 million to fund future capital expenditures in the joint venture agreement, related to this transaction. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

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 operations from the date of acquisition forward and due to the short time period held were 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 statements of operations 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.

10. Fair Value Measurements

We adopted the guidance and provisions of FASB ASC 820-10 (formerly SFAS No. 157) for financial assets and liabilities on January 1, 2008 and adopted the provisions for non-financial assets and liabilities on January 1, 2009. FASB ASC 820-10 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 guidance 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, 2009 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, 2009			
	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	$38.0	$38.0	$---	$ ---
Natural Gas Derivatives	$0.8	$---	$---	$ 0.8

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, 2009 (in millions):

Fair Value Reconciliation at December 31, 2009 – QTD	Hedging Contracts
Balance as of September 30, 2009	$---
Total gains (losses) (realized or unrealized):	
Included in earnings	(0.1)
Included in other comprehensive income	(0.3)
Purchases, issuances and settlements	1.2
Balance as of December 31, 2009	$0.8
The approximate amount of total gains for the period included in earnings (in Price Risk Management and Other, net) attributable to the change in unrealized gains relating to derivatives still held at December 31, 2009	$(0.1)

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, 2009 (in millions):

Fair Value Reconciliation at December 31, 2009 – YTD	Hedging Contracts
Balance as of December 31, 2008	$---

Total gains (losses) (realized or unrealized):	
Included in earnings	(1.4)
Included in other comprehensive income	(0.4)
Purchases, issuances and settlements	2.6
Balance as of December 31, 2009	$0.8
The approximate amount of total gains for the period included in earnings (in Price Risk Management and Other, net) attributable to the change in unrealized gains relating to derivatives still held at December 31, 2009	$(0.1)

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11. Condensed Consolidating Financial Information

Swift Energy Company is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is a guarantor of our senior subordinated notes due 2017 and 2020. The guarantees on our senior subordinated notes due 2017 and 2020 are full and unconditional. 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, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$---	$ 102,975	$ 5,625	$ ---	$ 108,600
Property and equipment	---	1,315,964	---	---	1,315,964
Investment in subsidiaries (equity method)	678,899	---	607,483	(1,286,382)	---
Other assets	---	10,201	75,850	(75,850)	10,201
Total assets	$ 678,899	$ 1,429,140	$ 688,958	$ (1,362,232)	$ 1,434,765
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$ 98,545	$ 5,059	$ ---	$ 103,604
Long-term liabilities	---	723,112	5,000	(75,850)	652,262
Stockholders' equity	678,899	607,483	678,899	(1,286,382)	678,899
Total liabilities and stockholders' equity	$ 678,899	$ 1,429,140	$ 688,958	$ (1,362,232)	$ 1,434,765

(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

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Condensed Consolidating Statements of Operations

(in thousands)	Year Ended December 31, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$---	$ 370,445	$ ---	$ ---	$ 370,445
Expenses	---	435,062	---	---	435,062
Loss before the following:	---	(64,617)	---	---	(64,617)
Equity in net earnings of subsidiaries	(39,330)	---	(39,076)	78,406	---
Loss from continuing operations, before income taxes	(39,330)	(64,617)	(39,076)	78406	(64,617)
Income tax benefit	---	(25,541)	---	---	(25,541)
Loss from continuing operations	(39,330)	(39,076)	(39,076)	78,406	(39,076)
Loss from discontinued operations, net of taxes	---	---	(254)	---	(254)
Net loss	$(39,330)	$ (39,076)	$ (39,330)	$ 78,406	$ (39,330)

(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
Loss before the following:	---	(412,758)	---	---	(412,758)
Equity in net earnings of subsidiaries	(260,490)	---	(257,130)	517,620	---
Loss from continuing operations, before income taxes	(260,490)	(412,758)	(257,130)	517,620	(412,758)
Income tax benefit	---	(155,628)	---	---	(155,628)
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 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 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
Income from discontinued operations, net of taxes	---	---	(131,301)	---	(131,301)
Net income	$21,287	$ 152,588	$ 21,287	$ (173,875)	$ 21,287

Condensed Consolidating Statements of Cash Flow

(in thousands)	Year Ended December 31, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$---	$ 226,176	$ (396)	$ ---	$ 225,780
Cash flow from investing activities	---	(184,549)	5,000	262	(179,287)
Cash flow from financing activities	---	(8,307)	262	(262)	(8,307)
Net increase (decrease) in cash	---	33,320	4,866	---	38,186
Cash, beginning of period	---	86	197	---	283
Cash, end of period	$---	$ 33,406	$ 5,063	$ ---	$ 38,469

(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

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, 2009:			
Proved oil and gas properties	$3,421,340	$3,421,340	$ ---
Unproved oil and gas properties	71,640	71,640	---
	3,492,980	3,492,980	---
Accumulated depreciation, depletion, and amortization	(2,196,444)	(2,196,444)	---
Net capitalized costs	$1,296,536	$1,296,536	$ ---
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	$ ---

Of the $71.6 million of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2009, excluded from the amortizable base, $13.3 million was incurred in 2009, $37.6 million was incurred in 2008, $4.1 million was incurred in 2007, and $16.6 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, 2009, 2008, and 2007.

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

	Year Ended December 31, 2009		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$---	$---	$ ---
Lease acquisitions and prospect costs1	61,105	61,105	---
Exploration	2,866	2,866	---
Development 2	111,095	111,095	---
Total acquisition, exploration, and development 3, 4	$175,066	$175,066	$ ---

	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 costs[1]	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

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 2009, 2008, and 2007 were $56.8 million, $56.7 million, and $50.2 million, respectively. Domestic costs for seismic data acquisition, included above, were $4.4 million, 12.4 million, and $11.6 million in 2009, 2008, and 2007, respectively. New Zealand costs for seismic data acquisition, included above were $0.5 million in 2007.

2 Facility construction costs and capital costs have been included in development costs, and totaled $18.4 million, $48.2 million, and $71.3 million for the years ended December 31, 2009, 2008, and 2007, respectively.

3 Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $24.5 million, $30.1 million, and $30.6 million in 2009, 2008, and 2007, respectively. In addition, the total includes $6.1 million, $8.0 million, and $9.5 million in 2009, 2008, and 2007, 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, 2009, 2008, and 2007.

Results of Operations (in thousands).

	Year Ended December 31, 2009		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$371,749	$371,749	$ ---
Lease operating cost	(76,744)	(76,740)	(4)
Severance and other taxes	(41,326)	(41,326)	---
Depreciation, depletion, and amortization	(162,908)	(162,908)	---
Accretion of asset retirement obligation	(2,906)	(2,906)	---
Write-down of oil and gas properties	(79,312)	(79,312)	---
	8,553	8,557	(4)
(Provision) Benefit for income taxes	(3,380)	(3,380)	---
Results of producing activities	$5,173	$5,177	$ (4)
Amortization per physical unit of production (equivalent Bbl of oil)	$17.99	$17.99	$ ---

	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	(224,201)	(219,344)	(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)
	(368,152)	(367,018)	(1,134)
(Provision) benefit for income taxes	138,444	138,366	78
Results of producing activities	$(229,708)	$(228,652)	$ (1,056)
Amortization per physical unit of production (equivalent Bbl of oil)	$21.43	$21.83	$ 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

These results of operations do not include the gains (losses) from our hedging activities of ($1.4) million, $26.1 million and 0.2 million for 2009, 2008 and 2007, respectively. Our lease operating costs per Boe produced were $8.47 in 2009, $10.44 in 2008, and $6.68 in 2007.

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 our domestic reserves were audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 96% of our 2009 domestic proved reserves, 97% of our 2008 domestic proved reserves and 100% of our domestic proved reserves for 2007. The audit by H.J. Gruy and Associates, Inc. conformed to the meaning of the term "reserves audit" as presented in Regulation S-K, Item 1202. 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 23, 2010, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2009, 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, 2006	324,131,417	82,119,084	269,660,791	73,464,531	54,470,626	8,654,552
Revisions of previous estimates[1]	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 estimates[1]	(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	---	---
Revisions of previous estimates[1]	(13,544,236)	(747,811)	(13,544,236)	(747,811)	---	---
Purchases of minerals in place	---	---	---	---	---	---
Sales of minerals in place	---	---	---	---	---	---
Extensions, discoveries, and other additions	32,874,203	3,069,361	32,874,203	3,069,361	---	---
Production	(21,157,002)	(5,529,059)	(21,157,002)	(5,529,059)	---	---
Proved reserves as of December 31, 2009	290,552,922	64,502,956	290,552,922	64,502,956	---	---
Proved developed reserves: [2]						
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	---	---
December 31, 2009	155,404,822	30,896,549	155,404,822	30,896,549	---	---

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, 2009 were based upon the preceding 12-months' average price based on closing prices on the first business day of each month, or prices defined by existing contractual arrangements are held constant, for that year's reserves calculation. Our hedges at year-end 2009 consisted of natural gas collars and price floors with strike price ranges outside the current period-end price and did not affect prices used in these calculations. At December 31, 2009 and 2008, we did not have any reserves in New Zealand. The 12-month average 2009 prices used in our calculations for domestic operations were $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL. The year-end 2008 prices used for domestic operations 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 per Mcf of natural gas, $93.24 per barrel of oil, and $56.28 per barrel of NGL at year-end 2007 for domestic operations. The 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. The 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.

[2] At December 31, 2009, 50% of our domestic reserves were proved developed, compared to 53% at December 31, 2008, and 48% at December 31, 2007. At December 31, 2007, 22% of our New Zealand reserves were proved developed.

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, 2009		
	Total	Domestic	Discontinued Operations
Future gross revenues	$4,358,412	$4,358,412	$ ---
Future production costs	(1,289,556)	(1,289,556)	---
Future development costs	(1,034,443)	(1,034,443)	---
Future net cash flows before income taxes	2,034,413	2,034,413	---
Future income taxes	(478,876)	(478,876)	---
Future net cash flows after income taxes	1,555,537	1,555,537	---
Discount at 10% per annum	(535,080)	(535,080)	---
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$1,020,457	$1,020,457	$ ---

	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)	---
	$1,033,004	$1,033,004	$ ---

Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves

	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

The standardized measure of discounted future net cash flows from production of proved reserves at year-end 2009 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 based on the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
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 the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. Our hedges at year-end 2009 consisted of natural gas collars and price floors with strike price ranges outside the current period-end price and did not affect prices used in these calculations. Subsequent changes to such 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 standardized measure of discounted future net cash flows for 2008 and 2007 were computed using rules in effect for those periods.

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

	Year Ended December 31,		
	2009	2008	2007
Beginning balance	$1,033,004	$2,636,443	$1,868,660
Revisions to reserves proved in prior years--			
Net changes in prices, net of production costs	149,000	(2,020,645)	1,259,492
Net changes in future development costs	(51,501)	(36,286)	(227,032)
Net changes due to revisions in quantity estimates	(53,094)	(229,290)	7,013
Accretion of discount	131,313	384,847	266,852
Other	(17,335)	(321,458)	(337,698)
Total revisions	158,383	(2,222,831)	968,627
	40,447	91,414	305,843

New field discoveries and extensions, net of future production and development costs			
Purchases of minerals in place	---	12,160	209,369
Sales of minerals in place	---	(90,148)	---
Sales of oil and gas produced, net of production costs	(253,683)	(616,272)	(533,934)
Previously estimated development costs incurred	64,033	290,337	230,046
Net change in income taxes	(21,727)	931,901	(412,168)
Net change in standardized measure of discounted future net cash flows	(12,547)	(1,603,439)	767,783
Ending balance	$1,020,457	$1,033,004	$2,636,443

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Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2009 and 2008 (in thousands, except per share data):

	Revenues	Income (Loss) from Continuing Operations Before Taxes	Income (Loss) from Continuing Operations	Loss from Discontinued Operations	Basic EPS from Continuing Operations	Diluted EPS from Continuing Operations
2009:						
First	$76,359	$(91,969)	$(59,003)	$ (126)	$(1.90)	$(1.90)
Second	82,921	(2,281)	(2,210)	(57)	(0.07)	(0.07)
Third	96,263	8,144	7,558	(32)	0.21	0.21
Fourth	114,902	21,489	14,579	(39)	0.38	0.38
Total	$370,445	$(64,617)	$(39,076)	$ (254)	$(1.16)	$(1.16)
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)

There were no extraordinary items in 2009 or 2008. Our New Zealand operations are accounted for as discontinued operations. In the fourth quarter of 2008 and first quarter of 2009, as a result of low oil and natural gas prices at December 31, 2008 and March 31, 2009, we reported non-cash write-downs on a before-tax basis of $754.3 million ($473.1 million after tax) and $79.3 million ($50.0 million after tax) on our oil and natural gas properties, respectfully.

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

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K and have determined that such disclosure controls and procedures are effective.

There was no change in our internal control over financial reporting during the quarter ended December 31, 2009 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, 2009 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 11, 2010, annual shareholders' meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 11, 2010, 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 11, 2010, 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 11, 2010, annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 11, 2010, 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 26, 2010, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

3. Exhibits

3.1	Certificate of Formation of Swift Energy Company (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Form 8-K filed November 3, 2009, File No. 1-08754).
3.2	Second Amended and Restated Bylaws of Swift Energy Company, effective October 30, 2009 (incorporated by reference as Exhibit 3.2 to Swift Energy Company's Form 8-K filed November 3, 2009, 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 May 19, 2009, 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 S-3 filed May 19, 2009, and amended June 17 and June 26, 2009, File No. 1-08754).
4.2	First Supplemental Indenture dated as of November 25, 2009, between Swift Energy Company, Swift Energy Operating, LLC, and Wells Fargo Bank, National Association, as Trustee, including the form of 8 7/8% Senior Notes (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 2, 2009, File No. 1-08754).
4.3	

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).

4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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	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).
10.5	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).
10.6+	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).
10.7+	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).

10.8	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).

10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	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.
10.14+	Amendment No. 1 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed April 1, 2009, File No. 1-08745).
10.15+	Amendment No. 2 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Form 8-K filed May 14, 2009, File No. 1-08754).
10.16	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).
10.17	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.

10.18	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).

10.19+	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).
10.20+	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).
10.21+	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).
10.22+	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).
10.23+	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).
10.24+	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).
10.25+	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).
10.26	Fifth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2009, 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 March 31, 2009 filed May 7, 2009).
10.27*	Sixth Amendment to First Amended and Restated Credit Agreement effective as of November 10, 2009, 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 .
10.28+	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).
10.29+	Employee Stock Purchase Plan, Generally Amended and Restated as of January 1, 2009.
12 *	Swift Energy Company Ratio of Earnings to Fixed Charges.

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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 23, 2010.

* 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 25, 2010
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 25, 2010
/s/ Barry S. Turcotte Barry S. Turcotte	Vice-President Controller Principal Accounting Officer	February 25, 2010
/s/ Deanna L. Cannon Deanna L. Cannon	Director	February 25, 2010
/s/ Raymond E. Galvin Raymond E. Galvin	Director	February 25, 2010

/s/ Douglas J. Lanier Douglas J. Lanier	Director	February 25, 2010
/s/Greg Matiuk Greg Matiuk	Director	February 25, 2010
/s/ Henry C. Montgomery Henry C. Montgomery	Director	February 25, 2010
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	February 25, 2010
/s/ Charles J. Swindells Charles J. Swindells	Director	February 25, 2010
/s/ Bruce H. Vincent Bruce H. Vincent	Director	February 25, 2010