SWIFT ENERGY CO
Form 10-K
February 23, 2012

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, 2011

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.
Yesþ No

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements

for the past 90 days.
Yes þ No

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

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

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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, 2011, the last business day of June 2011, was approximately $1,549,132,358.

The number of shares of common stock outstanding as of January 31, 2012 was 42,540,699.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 8, 2012	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 8, 2012

PART I

Items 1 and 2. Business and Properties

See pages 28 and 29 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 in Texas as well as onshore and in the inland waters of Louisiana. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. At year-end 2011, we had estimated proved reserves from our continuing operations of 159.6 MMBoe with a PV-10 of $1.9 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 2011 were approximately 20% crude oil, 64% natural gas, and 16% NGLs; and 35% of our total proved reserves were developed. Our proved reserves are concentrated with 79% in Texas and 21% in Louisiana.

We currently focus primarily on development and exploration of three core areas. The major fields in our core areas are:

- South Texas

  - Olmos

AWP
Sun TSH

  - Eagle Ford

AWP
Artesia Wells
Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central Louisiana/East Texas

Brookeland
South Bearhead Creek
Masters Creek
Burr Ferry

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 118.4 MMBoe to 159.6 MMBoe over the five-year period ended December 31, 2011. Over the same period, our annual production has grown from 9.4 MMBoe to 10.5 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our core areas.

During 2011, our proved reserves increased by 20%, due mainly to additional drilling in our South Texas core area. 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 use acquisitions to gain entry into new core areas and then increase reserves and production through development and exploratory activities within these areas. Through our strategic growth initiatives we target locations outside of our core areas for new exploration opportunities. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. We have replaced 185% of our production on average over the last five years with our new reserves.

We currently plan to balance our 2012 capital expenditures with our 2012 cash flow, cash on hand and potential line of credit borrowings. Our 2012 planned capital expenditures are $575 to $625 million with 75% to 80% focused on our continued development in the liquids rich acreage in the Eagle Ford shale and the Olmos sands in our South Texas area. The Company may also explore joint venture arrangements for particular prospects to accelerate drilling and development of its assets and diversify its risk profile. For 2012, we are targeting an increase in production volumes of 14% to 20% over 2011 levels and proved reserves growth of 10% to 15% over 2011 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 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 $9.95, $9.84 and $8.47 per Boe in 2011, 2010, and 2009, 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 types of 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, 2011. 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, in 1989 we acquired producing properties in the AWP field in Texas from a major producer. This field had been developed in the early 1980’s and was considered close to maturity when we made this acquisition. The Company began to acquire adjacent undeveloped acreage and in 1994 launched an aggressive drilling program. This area has remained a cornerstone of our operations as we have pursued other opportunities. Since assuming operations in this area, our drilling and completion techniques have been continuously refined to improve hydrocarbon recovery from the tight sand Olmos formation. Almost all of our existing interest overlays portions of the now very active Eagle Ford shale play which is being developed through the combination of horizontal drilling and multi-stage fracture stimulation completion techniques. While the combination of proven drilling and completion technologies have allowed us to begin to exploit the Eagle Ford shale, we have applied the same methods to further develop the “mature” Olmos sand. As a result we substantially increased our Olmos production and reserves during 2011 even though we have been producing from this formation for over 20 years. The Company has acquired 800 square miles of 3D seismic data over the AWP and Artesia Wells areas. In 2011 we merged and prestack time migrated 700 square miles of this data into a continuous volume that we are using to plan our wells and enhance and expand our developments at AWP. In late

2011 we initiated a project to merge and prestack time migrate an additional 100 square miles of data in the Artesia Wells area.

Another of our significant successes is the Lake Washington field. This 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 a peak of over 18,000 Boe. We have utilized enhanced 3-D seismic and various completion techniques including sliding sleeves to improve drilling success and production performance. When we acquired this field we booked 7.7 MMBoe of reserves. Since acquisition we produced approximately 48 MMBoe and still have remaining proved reserves of 14.4 MMBoe.

In October 2007, we acquired interests in two South Texas properties in the Gulf Coast basin (Sun TSH and Fasken) which, along with AWP, have acreage prospective for Eagle Ford shale development. These properties are located in the Sun TSH field in La Salle County and the Fasken field in Webb 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, 2011, our debt to capitalization was approximately 42%, while our debt to proved reserves ratio was $4.51 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 79 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 2011, we completed a project to reprocess, calibrate, merge and prestack time-migrate 700 square miles of 3-D seismic data over and near our AWP field. As these data were processed and merged with other available seismic data, and integrated with geologic data, we developed proprietary geo-science databases that we use to guide our exploration and development programs.

The application of horizontal drilling and multi-stage hydraulic fracturing technology has resulted in increases in production and decreases in completion and operating costs, particularly in our South Texas Olmos and Eagle Ford operations. In 2011, we successfully drilled 38 horizontal wells in our South Texas area using this technology. We will continue to improve and employ this new technology in South Texas and apply this to other areas in which we operate. We use numerous recovery techniques, including gas lift, acid treatments, water flooding, and pressure maintenance to enhance crude oil and natural gas production in all of our core operating areas. We also fracture reservoir rock through the injection of high-pressure fluid, the installation of gravel packs, and the insertion of coiled-tubing velocity strings to enhance and maintain production.

Swift Energy’s success at drilling both in South Texas and in Louisiana can be marked by requiring excellence in geosciences and engineering. This is accomplished by elevating the quality of engineering first and operations second, with a focus on continuing improvement. Specific drilling and completion guidelines and design specifications are developed and implemented as best practices and standards, respectively, from which all planning and execution is derived. The emphasis on well planning has permeated throughout the organization and the results of that planning constantly show up in performance across all operations. Lastly, the quality of the equipment and field personnel, together with a complete drilling process, is consistently enforced. This is the mixture of resources that aids Swift Energy in moving toward becoming a top tier company.

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Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2011 year-end proved reserves from continuing operations of 159.6 MMBoe and production of 10.5 MMBoe by area:

Core Area	Developed Reserves (MMBoe)	Undeveloped Reserves (MMBoe)	Total Proved Reserves (MMBoe)	% of Total Reserves	Oil and NGLs as % of Reserves	% of Total Production	Oil and NGLs as % of Production
AWP - Olmos	20.6	21.3	41.9	26.3 %	35.1 %	26.7 %	36.2 %
AWP – Eagle Ford	5.6	29.2	34.8	21.8 %	27.0 %	10.5 %	51.7 %
Fasken – Eagle Ford	6.7	27.2	33.9	21.3 %	0.0 %	13.6 %	0.0 %
Other South Texas	8.1	5.1	13.2	8.2 %	43.3 %	5.6 %	46.4 %
Total South Texas	41.0	82.8	123.8	77.6 %		56.4 %	
Southeast Louisiana	8.9	8.4	17.3	10.8 %	84.8 %	30.1 %	80.4 %
Central Louisiana / East Texas	5.7	12.7	18.4	11.5 %	66.5 %	13.1 %	58.7 %
Other	0.1	---	0.1	0.1 %	1.0 %	0.4 %	31.9 %
Total	55.7	103.9	159.6	100 %	35.6 %	100 %	49.7 %

Focus Areas

Our operations are primarily focused in three core areas identified as Southeast Louisiana, South Texas, and Central Louisiana/East Texas. 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 and Fasken area during 2007. 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 area was established when we acquired majority interests in producing properties in the Lake Washington field in early 2001 and in the Bay de Chene field in December 2004.

South Texas

AWP - Eagle Ford. In 2009 the Company initiated an active exploration and development program in the AWP Eagle Ford formation. During 2011 the Company drilled 17 wells in our AWP Eagle Ford field, including six non-operated joint venture wells. The Company owns a 50% working interest in the joint venture wells. These wells are operated by our partner during the drilling and completion phase. Swift Energy assumes operations when the wells are placed on production.

Based on the results of wells drilled in 2011 we have identified 81 proved undeveloped locations. During 2012 we plan to drill approximately 12 wells targeting the AWP Eagle Ford field. Our December 31, 2011 proved reserves in this formation are 73% natural gas, 10% oil, and 17% NGLs on a Boe basis.

AWP - Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled 12 horizontal Olmos wells in 2011. These wells were all operated and 100% owned by Swift Energy. We operate wells producing oil and natural gas from the Olmos sand formation at depths from 9,000 to 11,500 feet. Our South Texas reserves in this formation are approximately 65% natural gas, 27% NGLs, and 8% oil on a Boe basis.

At year-end 2011, we had 41 proved undeveloped locations in the Olmos. Our planned 2012 capital expenditures will include drilling approximately 14 horizontal wells targeting the Olmos formation, and we plan to perform approximately 15 production enhancement projects including fracture stimulations, pumping unit installations and installation of additional compression.

Fasken – Eagle Ford. During 2011 the Company drilled six operated wells in the Fasken Eagle Ford area. Based on the results of wells drilled in 2011 we have identified 41 proved undeveloped locations. During 2012 we plan to drill approximately two wells targeting the Fasken Eagle Ford area. Our December 31, 2011 proved reserves in this formation are 100% natural gas.

Artesia – Eagle Ford. During 2011 the Company drilled three operated wells in the Artesia Wells area. Based on the results of wells drilled in 2011 we have identified 10 proved undeveloped locations. During 2012 we plan to drill approximately 17 wells targeting the Artesia Eagle Ford area.

South Texas Acreage. As of December 31, 2011, we owned drilling and production rights to 79,308 net acres overlaying the Eagle Ford, of which 62,862 are undeveloped. We also owned drilling and production rights in 102,770 net acres overlying the Olmos (much of which also overlaps the Eagle Ford) in South Texas, of which 55,898 is undeveloped.

Southeast Louisiana

Lake Washington. As of December 31, 2011, we owned drilling and production rights in 14,722 net acres in the Lake Washington field located in Southeast Louisiana near shore waters within Plaquemines Parish. Since its discovery in the 1930's, the field has produced over 300 million Boe from multiple stacked Miocene sand layers radiating outward from a central salt dome and ranging in depth from 2,000 feet to 13,000 feet. The area around the dome is heavily faulted, thereby creating a large number of potential hydrocarbon traps. Approximately 92% of our proved reserves of 14.4 MMBoe in this field as of December 31, 2011, consisted of oil and NGLs. Oil and natural gas is gathered to several platforms located in water depths from 2 to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2011 we drilled two development wells. These two wells will yield between seven to 11 prospects in the future. In our production optimization program we performed 24 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At year-end 2011, we had 53 proved undeveloped locations in this field. Our planned 2012 capital expenditures in the field will include drilling up to 10 wells and performing recompletions on approximately 15 wells.

Bay de Chene. The Bay de Chene field is located along the border of Jefferson Parish and Lafourche Parish in near shore waters approximately 25 miles from the Lake Washington field. As of December 31, 2011, we owned drilling and production rights in approximately 14,653 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. During 2011 we did not drill any wells in the Bay De Chene field. At year-end 2011, we had two proved undeveloped locations in the Bay de Chene field. During 2012, we plan to drill one well in Bay de Chene.

Central Louisiana/East Texas

Burr Ferry. The Company has 73,679 net acres in the Burr Ferry field predominately located in Vernon Parish, Louisiana. Most of this acreage is within an area covered by a joint venture agreement with a large independent oil and gas producer. We entered into this joint venture agreement in 2009 for development and exploitation. In addition to holding a 50% working interest in the joint venture, the Company also owns fee mineral interest in approximately 29,000 unleased acres, primarily in our Burr Ferry field. During 2011 the Company drilled one non-operated well in this joint venture. The Company also drilled one operated well in this field, separate from the joint venture. The reserves are approximately 65% oil and NGLs. We have identified 10 additional proved undeveloped locations in this field. In 2012, we plan to drill between four to six wells and perform production enhancements on approximately two wells.

Masters Creek. As of December 31, 2011, we owned drilling and production rights in 37,685 net acres in the Masters Creek field. The Masters Creek field is located in Vernon Parish and Rapides Parish, Louisiana. Oil and natural gas wells are produced from the Austin Chalk formation within natural fractures encountered in the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 71% oil and NGLs. At year-end 2011, we had seven proved undeveloped locations. During 2011 we drilled one operated well in this field.

South Bearhead Creek. The South Bearhead Creek field 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 of over 4 million Boe. As of December 31, 2011, we owned drilling and production rights in 6,226 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 2011, we did not drill any wells in this field. At year-end 2011 we had 18 proved undeveloped locations in this field.

Brookeland. The Brookeland field area is located in Newton County and Jasper County, Texas, and Vernon Parish, Louisiana. As of December 31, 2011, we owned drilling and production rights in 68,270 net acres in this field. 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 57% oil and NGLs. During 2011 we drilled one non-operated well in this field.

Disposition. In October 2011, we sold our interests in six fields in South Louisiana, two in Texas and one in Alabama. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field includes Chunchula. We also retained deep mineral rights for certain fields included in this disposition.

Other

Four Corners. At the end of 2011, we had approximately 31,577 net acres leased in the Four Corners area of southwest Colorado. In 2012, we plan to drill up to three wells in this area.

New Zealand Areas (Discontinued Operations)

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. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result in the second quarter of 2011, the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. As of December 31, 2011, all payments under this sale agreement had been received and 100% of the Company’s oil and gas operations resided in the United States of America.

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 domestically as of December 31, 2011, 2010, and 2009. The information set forth in the tables regarding reserves is based on proved reserves reports we have prepared. Our Director of Reserves and 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 94% of our 2011 domestic proved reserves, 98% of our domestic proved reserves for 2010 and 96% of our domestic proved reserves for 2009. 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.

The reserves estimation process involves reserves coordinators who are senior petroleum reservoir engineers whose duty is to prepare estimates of reserves in accordance with the Commission's rules, regulations and guidelines, and who are part of multi-disciplinary teams responsible for each of the Company's major core asset areas. The multi-disciplinary teams consist of experienced reservoir engineers, geologists and other oil and gas professionals. Each reserves coordinator involved in the reserves estimation process has a minimum of 10 years reservoir engineering experience. The Director of Reserves and Evaluations supervises this process with multiple levels of review and reconciliation of reserves estimates to ensure they conform to SEC guidelines. Reserves data is also reported to and reviewed by senior management and the Board of Directors on a periodic basis. At year-end a reserves audit is performed by the third-party engineering firm, H.J. Gruy and Associates, Inc., to ensure the integrity and reasonableness of our reserves estimates. In addition, our independent Board members meet with H.J. Gruy and Associates, Inc. in executive session at least annually to review the annual audit report and the overall audit process.

A reserves audit and a financial audit are separate activities with unique and different processes and results. 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 years ended December 31, 2011,2010, and 2009 are made based on the preceding 12-months' average adjusted price after differentials based on closing prices on the first business day of each month, excluding the effects of hedging and are held constant, for that year's reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of natural gas contracts, the use of fixed and determinable contractual price escalations. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables.

The 12-month 2011 average adjusted prices after differentials for domestic operations were $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL, compared to $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL at year-end 2010 and $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL at year-end 2009.

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, 2011, 2010, and 2009. 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. 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,		
	2011	2010	2009
Estimated Proved Oil, NGL and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	184,355	190,454	155,405
Proved undeveloped	432,404	232,528	135,148
Total	616,759	422,982	290,553
Oil reserves (MBbl):			
Proved developed	13,840	16,782	19,659
Proved undeveloped	17,091	22,555	24,831
Total	30,931	39,337	44,490
NGL reserves (MBbl):			
Proved developed	11,078	11,874	11,237
Proved undeveloped	14,759	11,074	8,776
Total	25,837	22,948	20,012

Total Estimated Reserves (MBoe)	159,562	132,782	112,928
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$1,145	$974	$766
Proved undeveloped	773	803	557
PV-10 Value	$1,918	$1,777	$1,323

The PV-10 values for 2011, 2010, and 2009 are net of $75.0 million, $82.3 million, and $64.2 million of asset retirement obligation liabilities, respectively.

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reserves estimation 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,		
	2011	2010	2009
(in millions)			
PV-10 Value	$ 1,918	$ 1,777	$ 1,323
Future income taxes (discounted at 10%)	(400)	(432)	(302)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,518	$ 1,345	$ 1,021

Domestic Proved Undeveloped Reserves

The following table sets forth the aging of our domestic proved undeveloped reserves as of December 31, 2011:

Year Added	Volume (MMBoe)	% of PUD Volumes
2011	55.8	54 %
2010	33.8	32 %
2009	5.0	5 %
2008	3.3	3 %
2007	2.2	2 %
2006	3.8	4 %
Total	103.9	100 %

During 2011, we recorded 53.4 MMBoe of additional proved undeveloped reserves based on the results of the drilling program conducted during the year in the South Texas area. We also spent approximately $244 million in capital expenditures during the year to convert proved undeveloped reserves to proved developed reserves in our South Texas fields, resulting in the conversion of 12.3 MMBoe to proved developed reserves, which represents 17% of the prior year-end proved undeveloped reserves. Proved undeveloped reserves also decreased by approximately 8.6 MMBoe due to the sale of certain properties located in Louisiana, Texas and Alabama in October of 2011 as discussed in footnote 9 to our consolidated financials.

The PV-10 value from our proved undeveloped reserves was $0.8 billion at December 31, 2011 which was approximately 40% of our total PV-10 value of $1.9 billion. The PV-10 of our proved undeveloped reserves, by year of booking, are 4% in 2011, 49% in 2010, 2% in 2009, 15% in 2008, 12% in 2007 and 18% in 2006.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2011, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 159.6 MMBoe by approximately 0.3 MMBoe, and would increase the PV-10 Value of $1.9 billion by approximately $123 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.3 MMBoe and would decrease the PV-10 Value by approximately $122 million.

As of December 31, 2011 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.2 MMBoe and would increase the PV-10 Value by approximately $64 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.2 MMBoe and would decrease the PV-10 Value by approximately $64 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)
December 31, 2011:			
Gross	342	729	1,071
Net	316.5	699.2	1,015.7
December 31, 2010:			
Gross	485	846	1,331
Net	438.9	776.0	1,214.9
December 31, 2009:			
Gross	469	825	1,294
Net	406.6	758.9	1,165.5

(1) Excludes 38 service wells in 2011, 58 service wells in 2010 and 59 service wells in 2009.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2011:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	---	---	55,957	31,577
Louisiana (1)	107,943	91,625	117,077	69,593
Texas (2)	155,107	119,572	60,191	54,649
Wyoming	640	151	6,651	4,664
Total	263,690	211,348	239,876	160,483

(1) The Company holds the fee mineral (royalty) interest in a portion of the acreage located in Central Louisiana. The above table includes acreage where Swift is the fee mineral owner as well as a working interest owner. This

acreage included in the above table totals 13,469 gross and 10,889 net developed acres and 46,365 gross and 41,595 net undeveloped acres. The Company also owns fee mineral interest in approximately 29,000 acres that are currently unleased and not included in the table above.

(2) In South Texas a substantial portion of our Eagle Ford and Olmos acreage overlaps. In most cases the Eagle Ford and Olmos rights are contracted under separate lease agreements. For the purposes of the above table, a surface acre where we have leased both the Eagle Ford and Olmos rights is counted as a single acre. Acreage which is developed in any formation is counted in the developed acreage above, even though there may also be undeveloped acreage in other formations. In the Eagle Ford, we have 18,366 gross and 16,446 net developed acres and 77,474 gross and 62,862 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos we have 47,611 gross and 47,872 net developed acres and 59,189 gross and 55,898 net undeveloped acres.

As of December 31, 2011, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 28% in 2012, 32% in 2013 and 2% in 2014. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options.