SWIFT ENERGY CO
Form 10-K
February 22, 2013

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, 2012

Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes	þ	No	o

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	o	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	o	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.
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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 o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes	o	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, 2012, the last business day of June 2012, was approximately $778,385,135.

The number of shares of common stock outstanding as of January 31, 2013 was 43,002,344.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 21, 2013	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

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(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 21, 2013

Items 1 and 2. Business and Properties

See pages 27 and 28 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 December 31, 2012, we had estimated proved reserves of 192.1 MMBoe with a PV-10 Value of $2.3 billion (PV-10 Value 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). Our total proved reserves at December 31, 2012 were approximately 22% crude oil, 52% natural gas, and 26% NGLs while 34% of our total proved reserves were developed. Our proved reserves are concentrated with 82% in Texas and 18% 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

  Eagle Ford
  AWP
  Artesia Wells
  Fasken

- Southeast Louisiana
  Lake Washington
  Bay De Chene

- Central Louisiana / East Texas
  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 133.8 MMBoe to 192.1 MMBoe over the five-year period ended December 31, 2012. Over the same period, our annual production has grown from 10.6 MMBoe to 11.7 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our core areas. During 2012, 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 currently plan to fund our 2013 capital expenditures with our 2013 cash flow, cash on hand and potential line of credit borrowings. Our 2013 planned capital expenditures are $440 to $480 million focused on continued development of oil and liquid rich properties. The Company is also exploring joint venture arrangements for a portion of our Eagle Ford properties to accelerate drilling and development, monetize a portion of those asset values, diversify its risk profile and possibly free up capital dollars for other purposes. In addition, where appropriate we evaluate our properties for divestiture of assets that no longer optimally fit our strategy. Currently this includes our Brookeland field. For 2013, The Company is targeting production up to 3% over 2012 levels and proved reserves to increase 7% to 12% over year-end 2012 quantities with a focus on oil and liquid rich opportunities.

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. We have replaced 217% of our production on average over the last five years with our new reserves.

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, excluding taxes, were $9.87, $9.95 and $9.84 per Boe for the years ended December 31, 2012, 2011 and 2010, 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 94% of our proved oil and natural gas reserves base as of December 31, 2012. 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 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 2012 we completed 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 historical 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 50 MMBoe and still have remaining proved reserves of 12.5 MMBoe.

In October 2007, we acquired interests in two South Texas properties in the Gulf Coast basin which, along with AWP, have acreage in the Eagle Ford shale. 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, 2012, our debt to capitalization ratio was approximately 47%, while our debt to proved reserves was $4.77 per Boe, and our debt to PV-10 Value ratio was 40%. 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 72 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 six 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 2012, we completed a project to invert, calibrate, merge and prestack time-migrate our 700 square miles of merged 3-D seismic data over and near our AWP field. As these data were updated 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 2012, we successfully drilled 55 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 2012 year-end proved reserves from continuing operations of 192.1 MMBoe and production of 11.7 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
Artesia Wells - Eagle Ford	15.5	54.6	70.1	36.5 %	50.7 %	13.0 %	46.4 %
AWP - Eagle Ford	8.7	27.1	35.8	18.6 %	43.2 %	12.7 %	65.3 %
AWP - Olmos	17.3	13.0	30.3	15.8 %	42.1 %	26.8 %	42.5 %
Fasken - Eagle Ford	5.7	9.9	15.6	8.1 %	— %	18.5 %	— %
Other South Texas	4.8	—	4.8	2.6 %	47.7 %	2.1 %	45.2 %
Total South Texas	52.0	104.6	156.6	81.6 %		73.1 %	
Southeast Louisiana	7.9	7.1	15.0	7.8 %	84.9 %	19.0 %	86.3 %
Central Louisiana / East Texas	5.7	14.7	20.4	10.6 %	67.4 %	7.7 %	65.2 %
Other	0.1	—	0.1	— %	1.0 %	0.2 %	26.3 %
Total	65.7	126.4	192.1	100.0 %	48.1 %	100.0 %	48.2 %

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. During 2012 the Company drilled 22 wells in our AWP Eagle Ford field, of which three were joint venture wells. The Company owns a 51% working interest in these joint venture wells. These wells were all drilled and operated by Swift Energy. At December 31, 2012, we had identified 73 proved undeveloped locations. Our December 31, 2012 proved reserves in this formation are 57% natural gas, 25% NGLs, and 18% oil on a Boe basis. During 2013 we plan to drill approximately 10 wells targeting the AWP Eagle Ford field.

AWP - Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled nine horizontal Olmos wells in 2012. 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 58% natural gas, 30% NGLs, and 12% oil on a Boe basis. At December 31, 2012, we had 35 proved undeveloped locations in the Olmos. Our planned 2013 capital expenditures will include drilling approximately six horizontal wells targeting the Olmos formation.

Artesia Wells - Eagle Ford. During 2012 the Company drilled 22 operated wells in the Artesia Wells area. These wells were all operated and 100% owned by Swift Energy. Our December 31, 2012 proved reserves in this formation are 49% natural gas, 35% NGLs, and 16% oil on a Boe basis. At December 31, 2012, we had identified 84 proved undeveloped locations. During 2013 we plan to drill approximately 13 wells targeting the Artesia Wells area.

Fasken - Eagle Ford. During 2012 the Company drilled two operated wells in the Fasken Eagle Ford area. At December 31, 2012, we had identified 14 proved undeveloped locations. During 2013 we plan to drill two wells targeting the Fasken Eagle Ford area.

South Texas Acreage. As of December 31, 2012, we have 27,727 gross and 25,700 net developed acres and 64,542 gross and 50,192 net undeveloped acres in the Eagle Ford. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos we have 50,532 gross and 50,041 net developed acres and 52,893 gross and 48,919 net undeveloped acres. We have begun conducting downspacing tests to optimize the development of many of our Eagle Ford acreage positions.

Pursuit of Eagle Ford Joint Venture. We are currently exploring opportunities to enter into a joint venture arrangement with prospective partners in order to monetize our highest value acreage in our Eagle Ford properties, while at the same time creating opportunities to accelerate development of these properties in South Texas. Entering into a joint venture agreement would accelerate drilling and offer additional capital that we could deploy for our development program in other areas. We are targeting completion of this initiative by the third quarter of 2013.

Southeast Louisiana

Lake Washington. As of December 31, 2012, we owned drilling and production rights in 15,231 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 12.5 MMBoe in this field as of December 31, 2012, 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 2012 we drilled 10 development wells. In our production optimization program we performed 20 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At December 31, 2012, we had 53 proved undeveloped locations in this field. We will reduce our planned 2013 capital expenditures in the field but plan to drill three wells and perform recompletions on approximately 12 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, 2012, we owned drilling and production rights in approximately 14,253 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. During 2012, we drilled one well in the Bay De Chene field. At December 31, 2012, we had two proved undeveloped locations in the Bay de Chene field.

Central Louisiana/East Texas

Burr Ferry. The Company has 118,638 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 13,068 unleased acres, primarily in our Burr Ferry field. During 2012, the Company drilled four non-operated wells and one operated well in this joint venture. The reserves are approximately 66% oil and NGLs. We have identified 18 additional proved undeveloped locations in this field. In 2013, we plan to drill approximately three wells.

Masters Creek. As of December 31, 2012, we owned drilling and production rights in 37,458 net acres in the Masters Creek field. The Masters Creek field is located in Vernon Parish and Rapides Parish, Louisiana. Oil and natural gas 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 December 31, 2012, we had six proved undeveloped locations. During 2012 we did not drill any wells 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, 2012, we owned drilling and production rights in 5,901 net acres in this field. Wells drilled in this field are completed in a multiple set of separate sands in the Wilcox formation. In 2012, we did not drill any wells in this field. At December 31, 2012 we had 18 proved undeveloped locations in this field. During 2013, we plan to drill one oil test infill well in this area using horizontal drilling and multi-stage hydraulic fracturing technologies.

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 December 31, 2012, we had approximately 51,428 net acres leased in the Four Corners area of southwest Colorado. This high quality, cost effective and meaningful acreage position prospective for shallow, oil-rich, Niobrara production, is primarily in La Plata County, Colorado. In 2013, we plan to drill an exploratory well in this area later in the year, and have already conducted detailed analysis of the basin, production history and other current activity in the 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, 2012, 2011 and 2010. The information set forth in the tables regarding reserves is based on proved reserves reports we have prepared. Our Chief Reserves Engineer, 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%, 94% and 98% of our domestic proved reserves for the years ended December 31, 2012, 2011 and 2010. 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 30 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 Chief Reserves Engineer 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 reserves audit report and the overall reserves 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, 2012, 2011 and 2010 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 following prices are used to estimate our year-end PV-10 Value. The 12-month 2012 average adjusted prices after differentials for domestic operations were $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL, compared to $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL at year-end 2011 and $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL at year-end 2010.

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, 2012, 2011 and 2010. 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 (the "Standardized Measure"), which is calculated after provision for future income taxes. The following amounts shown in MBoe below are based on a natural gas conversion factor of 6 Mcf to 1 Boe:

Estimated Proved Oil, NGL and Natural Gas Reserves	As of December 31,		
	2012	2011	2010
Natural gas reserves (MMcf):			
Proved developed	195,643	184,355	190,454
Proved undeveloped	401,926	432,404	232,528
Total	597,569	616,759	422,982
Oil reserves (MBbl):			
Proved developed	17,780	13,840	16,782
Proved undeveloped	25,479	17,091	22,555
Total	43,259	30,931	39,337
NGL reserves (MBbl):			
Proved developed	15,328	11,078	11,874
Proved undeveloped	33,891	14,759	11,074
Total	49,219	25,837	22,948
Total Estimated Reserves (MBoe)	192,073	159,562	132,782
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$1,201	$1,075	$976
Proved undeveloped	1,083	843	801
PV-10 Value	$2,284	$1,918	$1,777

The PV-10 Values for the years ended December 31, 2012, 2011 and 2010 are net of $89.6 million, $75.0 million, and $82.3 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.

PV-10 Value is a non-GAAP measure. The closest GAAP measure to the PV-10 Value is the Standardized Measure. We believe the PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the value of proved reserves on a comparative basis across companies or specific properties. We use the PV-10 Value in our ceiling test computations, for comparison against our debt balances, to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. The following table provides a reconciliation between the PV-10 Value and the Standardized Measure.

	As of December 31,		
(in millions)	2012	2011	2010
PV-10 Value	$ 2,284	$ 1,918	$ 1,777
Future income taxes (discounted at 10%)	(412)	(400)	(432)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,872	$ 1,518	$ 1,345

Domestic Proved Undeveloped Reserves

The following table sets forth the aging of our domestic proved undeveloped reserves as of December 31, 2012:

Year Added	Volume (MMBoe)	% of PUD Volumes
2012	68.9	55 %
2011	34.5	27 %
2010	15.0	12 %
2009	2.8	2 %
2008	2.8	2 %
Prior to 2008	2.4	2 %
Total	126.4	100 %

During 2012, we recorded 33.2 MMBoe of additional proved undeveloped reserves based on the results of the drilling program conducted during the year in the Artesia Wells and Burr Ferry fields. Additional changes included performance-related additions of 22.8 MMBoe in proved undeveloped reserves in the liquids rich Artesia Wells field, largely offset by reductions of 19.1 MMBoe in proved undeveloped reserves in the Fasken field due to low natural gas prices. We also spent approximately $135 million in capital expenditures during the year to convert 7.3 MMBoe of our December 31, 2011 proved undeveloped reserves to proved developed reserves, primarily in the Artesia Wells field.

The PV-10 Value from our proved undeveloped reserves was $1.1 billion at December 31, 2012 which was approximately 47% of our total PV-10 Value of $2.3 billion. The PV-10 Value of our proved undeveloped reserves, by year of booking, was 66% in 2012, 3% in 2011, 15% in 2010, less than 1% in 2009, 8% in 2008 and 8% prior to 2008.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2012, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 192.1 MMBoe by approximately 0.5 MMBoe, and would increase the PV-10 Value of $2.3 billion by approximately $174 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.7 MMBoe and would decrease the PV-10 Value by approximately $173 million.

As of December 31, 2012, a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.3 MMBoe and would increase the PV-10 Value by approximately $43 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.3 MMBoe and would decrease the PV-10 Value by approximately $42 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, 2012			
Gross	375	744	1,119
Net	345.9	713.5	1,059.4
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	1,214.9

(1) Excludes 59, 38 and 58 service wells added in 2012, 2011 and 2010.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2012:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	—	—	73,616	51,428
Louisiana (1)	144,408	125,824	128,388	78,899
Texas (2)	135,866	113,730	47,542	42,183
Wyoming	—	—	10,390	8,174
Total	280,274	239,554	259,936	180,684

(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 50,777 net developed mineral acres and 23,998 net undeveloped mineral acres. The Company also owns fee mineral interests in approximately 13,068 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 27,727 gross and 25,700 net developed acres and 64,542 gross and 50,192 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos, we have 50,532 gross and 50,041 net developed acres and 52,893 gross and 48,919 net undeveloped acres.

As of December 31, 2012, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 12% in 2013, 7% in 2014 and 6% in 2015. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options.

Drilling and Other Exploratory and Development Activities

The following table sets forth the results of our drilling activities during the years ended December 31, 2012, 2011 and 2010:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2012	Exploratory	—	—	—	—	—	—
	Development	71	71	—	66.2	66.2	—
2011	Exploratory	—	—	—	—	—	—
	Development	44	44	—	39.6	39.6	—
2010	Exploratory	11	10	1	9.5	8.5	1.0
	Development	45	38	7	41.9	34.9	7.0

Present Activities

As of December 31, 2012, we were in the process of drilling two wells in our South Texas Area, in which we own a 100% working interest, and one well in the Burr Ferry field, in which we own a 50% working interest. We have also continued the production optimization program in the Lake Washington field to mitigate natural field declines, involving recompletions, stimulations, gas lift enhancements and sliding sleeve shifts to change productive zones.

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.

Operations on our oil and natural gas properties are customarily administrated in accordance with COPAS guidelines. We charge a monthly per-well supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. 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 2012 totaled $11.3 million and ranged from $374 to $2,934 per well per month.

Fixed and Determinable Commitments

As of December 31, 2012, we had natural gas sales commitments to deliver fixed and determinable quantities of natural gas under term contracts as follows:

Year	Delivery Quantity (MMBTU)
2013	—
2014	7,650,000
2015	6,680,000

The sales price is tied to current spot gas prices at the time of delivery. Delivery quantities in excess of the minimums for any given year will proportionally reduce the minimum quantities for subsequent periods. The delivery point is in South Texas, and the Company's proven reserves and production rates in the area significantly exceed the minimum obligations. There is no dedication of production from specific leases under the agreement.

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. For the years ended December 31, 2012, 2011 and 2010, Shell Oil Company and affiliates accounted for 46%, 49% and 52% of our total oil and gas gross receipts, respectively. Southcross Energy accounted for approximately 11% of our total oil and gas gross receipts in 2012, while Flint Hills Resources accounted for approximately 14% of our total oil and gas gross receipts in 2011. No other purchasers accounted for more than 10% of our total oil and gas gross receipts for the past three years. Credit losses in each of the last three years were immaterial. Due to the demand for oil and natural gas and the 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 either 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). Historically, 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 (the segment of line into which Swift delivers its gas was sold to High Point Energy, LLC in 2012) and for the processing of natural gas delivered to Sonat at the Toca Plant.

In 2011, we entered into gas processing and gathering agreements with Southcross Energy for a majority of our natural gas production in the AWP area, replacing agreements with Enterprise Texas Pipeline and Enterprise Hydrocarbons. The processed natural gas liquids are sold to Southcross. The residue gas is sold at prevailing prices to Southcross and other parties at downstream connections on Southcross' system. Other gas production in the AWP area is processed or transported under arrangements with Houston Pipe Line, DCP Midstream and Enterprise. Oil production is transported to market by truck or pipeline and sold at prevailing market prices.

In the Sun TSH and Fasken fields, our oil production is sold at prevailing market prices and transported to market by truck. Natural gas from the fields has historically been 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 natural gas 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. In the fourth quarter of 2010, Meritage Midstream Services, LLC completed construction of a new pipeline to the Fasken area. We entered into a gathering agreement providing for the transportation of our Eagle Ford production on the new pipeline from Fasken to Kinder Morgan Texas Pipeline, where it is sold at prices tied to monthly and daily natural gas price indices. The Meritage pipeline was sold to Howard Energy in 2012.

In 2012, we entered into an agreement with Eagle Ford Gathering LLC that provides for the gathering and processing for almost all of our natural gas production in the Artesia Wells area. The processed natural gas liquids are purchased by Eagle Ford Gathering. The residue gas is sold to various parties at prevailing market prices at connections downstream of the processing facilities. For natural gas deliveries to Enterprise, Enterprise purchases the processed liquids when processing is available, with the residue gas sold at prevailing market prices. In the Artesia Wells area, our oil production is sold at prevailing market prices and transported to market by truck.

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. There is field level extraction of a portion of the NGLs in the gas stream prior to delivery to Trunkline. Those NGLs are stored in a pressurized vessel and transported by truck to market for sale at prevailing market prices.

Our oil production from the Bay de Chene field is transported on barges for sales to various purchasers at prevailing market prices. Natural gas production is sold into an intrastate pipeline with prices tied to monthly and daily natural gas price indices.

The prices in the tables below 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.